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The Province of Alberta

NATURAL GAS COMMISSION

Enquiry into Reserves and Consumption
of Natural Gas in the Province
of Alberta

REPORT OF THE COMMISSION

R. J. DINNING, Esq. (Chairman)

A. STEWART, Esq. (Commissioner)

R. C. MARLER, Esq. (Commissioner)

D. P. McDONALD, Esq., K.C. (Commission Counsel)

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COMMISSION

"J. C. BOWEN"
Lieutenant Governor

PROVINCE OF ALBERTA
CANADA

GEORGE THE SIXTH, by the Grace of God, of Great Britain, Ireland and the British Dominions beyond the Seas, King, Defender of the Faith.

To all to whom these presents shall come, or whom the same may in any wise concern,

GREETINGS:

WHEREAS, under the provisions of The Public Inquiries Act, being Chapter 139 of the Revised Statutes of Alberta, 1942, the Lieutenant Governor in Council may whenever he deems it expedient and in the public interest to cause inquiry to be made into and concerning any matter within the jurisdiction of the Legislative Assembly, either connected with the good government of the Province of Alberta or the conduct of the public business thereof, or which he shall by his commission declare to be a matter of public concern, appoint a Commissioner or Commissioners to make such such inquiry and to report thereon; and

WHEREAS it is deemed expedient and in the public interest that inquiry be made under the provisions of the Public Inquiries Act, being Chapter 139 of the Revised Statutes of Alberta, 1942, in order to investigate the proven and estimated reserves of natural gas in the Province of Alberta, and also the present and estimated future consumption of natural gas for domestic and industrial purposes.

NOW KNOW YE that by and with the advice of Our Lieutenant Governor in Council, We do by these Presents nominate, constitute and appoint, pursuant to the provisions of the Public Inquiries Act, being Chapter 139 of the Revised Statutes of Alberta, 1942, Robert J. Dinning, of the City of Calgary, in the Province of Alberta, Andrew Stewart, of the City of Edmonton, in the Province of Alberta, and Roy C. Marler, of the Hamlet of Bremner, in the Province of Alberta, as Commissioners to conduct the said inquiry:

(1) to investigate the existing and proven reserves of natural gas in the Province of Alberta;

(2) to inquire into and estimate the potential reserves of natural gas in the Province of Alberta;

(3) to inquire into the present domestic, commercial and industrial consumption of natural gas in the Province of Alberta;

(4) to estimate the future requirements of natural gas for domestic, commercial and industrial purposes in the Province of Alberta;

(5) to make such further inquiries into the situation surrounding the use of natural gas in the Province of Alberta as they may deem necessary, having in mind the best interests of the people of the Province of Alberta;

(6) to report their findings to the Lieutenant Governor in Council.

AND WE DO DECLARE the matters referred to Our said Commissioners to be matters of public concern.

AND WE DO CONFER under authority of the Act aforesaid upon Our said Commissioners the power of summoning witnesses before them and requiring such witnesses to give evidence on oath, orally, in writing or on solemn affirmation (if they are persons entitled to affirm in civil matters), and to produce such documents and things as Our said Commissioners may deem requisite to the full investigation of the matters into which they are appointed to inquire, and further conferring upon Our said Commissioners the same power to enforce the attendance of witnesses and to compel them to give evidence as is vested in any court of record in civil cases.

IN TESTIMONY WHEREOF We have caused these Our Letters to be made Patent, and the Great Seal of Our Province of Alberta to be hereunto affixed.

WITNESS: His Honour the Honourable John Campbell Bowen, Lieutenant Governor of Our said Province, in Our City of Edmonton, this 2nd day of November, in the year of Our Lord, One Thousand, Nine Hundred and Forty-eight, and in the Twelfth year of Our Reign.

BY COMMAND

"A. J. HOOKE"
Provincial Secretary.

The Commission, in the short time at its disposal, has endeavored to compile and present all available factual data. In keeping with the terms of the Reference, above set out, the Commission has not made any recommendation regarding the question of the export of natural gas.

To: HIS HONOUR,

THE LIEUTENANT GOVERNOR OF THE PROVINCE OF ALBERTA.

In submitting our report in connection with Natural Gas in Alberta, we wish to express our full appreciation for the valuable assistance tendered to us by all those who contributed, so generously, to the compilation of the information submitted herewith.

The oil and gas Companies in the producing, exploration and distributing fields, freely tendered their statistical records and their officers gave generously of their time.

Submissions by those advocating the export of gas outside the Province were capably presented by men high in the engineering profession.

Prominent chemical, oil, gas and consulting Engineers and Geologists in Canada and the United States appeared before the Commission and their evidence disclosed a detailed technical knowledge of the subject matter under review.

Representatives of Agriculture, Manufacturers' Associations, Coal Operators' Associations, Chambers of Commerce and Urban Municipalities submitted their representations in definite and concrete language.

It is our pleasure, at the conclusion of this inquiry, to state our appreciation of the services rendered by the Counsel to the Commission. His energy and initiative and his knowledge of the oil and gas industry, in no small way, contributed to the compiling of this report.

To the Staff of the Research Council of Alberta and the officers of the Conservation Board, we express our gratitude for their never-failing assistance and courtesy.

SCOPE OF INQUIRY

The amount of the reserves of natural gas in Alberta and the extent of possible future uses of natural gas in the province had been under consideration by officials of the Governments of Alberta and of the Dominion, and of the oil and gas companies, for some time prior to the appointment of the Commission. The Minister of Mines and Resources of the Dominion Government appointed Dr. G. S. Hume, of the Geological Survey of Canada, and A. Ignatieff of the Bureau of Mines of the Department of Mines and Resources, to report on the natural gas reserves of the Prairie Provinces. Their report was published in April, 1948.

Parties in the United States, interested in the transmission of natural gas from Alberta to the Pacific northwestern States, and to Trail and Vancouver in British Columbia, conducted independent surveys and encouraged the companies controlling natural gas reserves in Alberta to investigate and prepare reports on their holdings. In addition, parties in Manitoba had prepared material with respect to the building of a transmission pipe line from Alberta to service areas in Saskatchewan and Manitoba.

There was therefor readily available to the Commission the report of Hume and the reports prepared by the company geologists, together with material gathered by the proposed purchasers of natural gas for transmission outside of the province.

A notice of the appointment of the Commission and the terms of references were sent to all parties deemed to be interested, including all towns and cities in the province, and a notice of the time and place of hearings of the Commission was published in the daily newspapers of Medicine Hat, Lethbridge, Calgary and Edmonton.

The Commission held public hearings at Medicine Hat on one day, at Calgary on 22 days, and at Edmonton on 5 days. In addition to public hearings, a number of individuals and groups in the Province filed written submissions with the Commission. In all, testimony was received from 49 witnesses. The record amounted to 2541 pages of transcript and 134 exhibits were filed.

SUMMARY OF EVIDENCE

The testimony at the public hearings and the written submissions filed with the Commission fall into two classifications, namely—technical evidence and general representations. A brief summary of the testimony and submissions received in these two classifications is set out below. A more complete review of the testimony and submissions, and the view of the Commission with respect thereto, are set out in the following parts of the report.

The technical evidence is divided into two categories, namely—evidence as to the reserves of natural gas and evidence as to the consumption of natural gas.

RESERVES

There was a marked unanimity of opinion in the evidence of the geologists with respect to the existing and proven reserves of gas in the Province. The methods of estimating the reserves adopted by Hume[1] and Ignatieff in their report of April, 1948, were closely followed by the other geologists and therefore Hume's report has served as a basis of comparison in respect to all the submissions received.

The geologists did not express a quantitative opinion in respect to the potential or anticipated future growth and establishment of reserves of natural gas in the Province, but limited their testimony to expressions of opinion related to the past developments in the Province, to the estimated rate of future exploratory drilling, and to consideration of the areas in the Province believed to be favourable for the finding of oil and gas.

Hume's revised estimate of the existing and proven reserves of natural gas was 4.261 trillion cubic feet at an abandonment pressure of 100 pounds p.s.i.a. 60°F. Hume did not estimate the potential reserves of the Province, but he did list twenty-seven areas in which significant occurrences of gas were indicated by wells drilled and tested. He referred to the improved methods of testing prospective producing horizons now generally followed during drilling operations, and to the increased appreciation of the value of gas, as factors tending toward the establishment of further reserves of gas as exploratory drilling for oil is being carried on in the future. Basing his opinion on his long experience in studying the geology of Alberta and recording the results of drilling in the Province, Hume stated that he considered the potential reserves will exceed those now existing and proven, many times.

G. E. Liesemer,[2] Chief Engineer of the Alberta Petroleum and Natural Gas Conservation Board, testified with respect to a number of the areas in the Province in which gas was being produced, particularly in the Medicine Hat field, in which he estimated the remaining reserve of gas exceeded 300 billion cubic feet at 100 pounds p.s.i.a., 60°F. His estimates in respect to other producing areas were substantially in agreement with those of Hume, except the Viking-Kinsella field, in which his estimate was 190 billion cubic feet less than Hume's estimate. He did not express any opinion as to potential reserves or areas from which production had not been taken.

A. R. Crozier[3], Fuel Controller of the Province of Ontario, stated that the production of natural gas from Ontario fields from 1890 to the end of 1947 amounted to 435.6 billion cubic

(1) Tr. Vol. 2
(2) Tr. Vol. 1
(3) Tr. Vol. 22

feet. The annual production for 1947 was 7.7 billion cubic feet. The remaining reserves of natural gas are now estimated to be approximately 75 billion cubic feet. He indicated that the greatest production was taken during the period 1914 to 1920 during which production reached the peak rate of 20 billion cubic feet per year, and the fields approached exhaustion. In 1919 a Conservation Act was passed to govern the orderly marketing of the gas in view of the increased demand and diminishing supply. His evidence demonstrated that with a demand for gas at high prices production can be taken at low pressure, there being numerous wells in Ontario now producing at less than 100 pounds p.s.i.a. and some at 50 pounds or less.

Dr. Albert D. Brokaw [1], a Director of the Northwest Natural Gas Company, a company formed in the United States for the purpose of purchasing and transmitting Alberta gas to the Pacific Northwest States, and Trail and Vancouver in British Columbia, substantially supported Hume's estimates of existing and proven reserves and stated that, considering the current and prospective rate of exploration, it is almost certain that the present proven reserves of the province will be increased to many times the present estimates, repeating the experience that has followed development in other large potential gas areas in the United States.

A. F. Dixon [2], the President and a Director of the Northwest Natural Gas Company, expressed the view that the potential reserves of gas in Alberta were very large. He based his opinion on the extent of the sedimentary deposits in Alberta favorable to the occurrence of gas and he supported his statements by referring to the development of the gas resources of the States of Texas and Oklahoma.

Dr. T. A. Link [3], a prominent Canadian geologist, called by the Northwest Natural Gas Company, agreed with Hume's estimate of existing and proven reserves. He directed his testimony to the extent of the potential production of gas. He outlined the nature and extent of the sedimentary rocks existing in the province and compared the rate of exploration to date with the rate of exploration carried out in the State of Kansas and concluded that it would be reasonable to assume that in the very near future, Alberta should develop about 28 trillion cubic feet, about twice the reserves of that State, and that the reserves developed in Alberta within the next five years will amount to not less than 10 trillion cubic feet.

The Northwest Natural Gas Company arranged for the attendance before the Commission of W. C. Spooner[4], a consulting geologist of Shreveport, Louisiana, who conducted a survey of Alberta gas resources for the Internationl Utilities Company. Spooner's estimate of existing and proven resources in general agreed with that of Hume, with the exception that he included in his estimate 500 billion cubic as the amount of the proven reserve in the Pincher Creek area.

Spooner dealt at considerable length with the methods of estimating potential reserves and indicated that, on the assumption that drilling and exploration activities would continue for the next five years at the rate experienced in the last five years, it was reasonable to assume that the Alberta reserves of natural gas would increase by not less than 3 trillion cubic feet in the next five years.

Spooner referred in detail to the experience in the State of Louisiana, where over many years the rate of new discovery of reserves of gas closely followed the rate of exploration and drilling. He based his opinion of the presence of great volumes of recoverable gas in Alberta on the extent of favourable sedimentary deposits in the Province. He concluded the slight footage drilled per square mile in the Province indicates conclusively that the oil and gas de-

(1) Tr. Vol. 6
(2) Tr. Vol. 9 to 13, Vol. 21
(3) Tr. Vol. 6, 9 & 22
(4) Tr. Vol. 17

velopment of Alberta is in its initial stage, and that current reserves of gas represent but a small fraction of the ultimate gas reserve that will be developed over a period of years.

Dr. J. F. Dodge [1], consulting geologist of Los Angeles, California, called by the Shell Oil Company of Canada Limited, dealt particularly with the Jumping Pound area, controlled by that Company. His estimate of existing and proven reserves for an area of 5700 acres, was slightly over 1 trillion cubic feet recoverable gas, predicated upon an abandonment pressure of 400 pounds, p.s.i.a., as contrasted to Hume's estimate of 920 billion cubic feet to an abandonment pressure of 100 pounds, p.s.i.a. for an area of 6300 acres. Dodge stated, with regard to the potential reserves,—

> "... there are a great number of fields and a large amount of reserves to be found in Alberta. The province has the sediment and source material for the essential accumulation of oil and gas. All that is required, at the present time, is to find the structures and drill them".

He did not express a quantitative opinion, but stated his view that the potential reserves are clearly in excess of existing and proven reserves today.

The geologists called by the producing companies, namely, Robert Pot[2] and Dr. Ernest W. Shaw[3] for the Imperial Oil Limited; Dr. Hugh H. Beach[4] for the McColl-Frontenac Oil Company Limited; Dr. James D. Weir[5] of the California Standard Company, and Gordon Connell[6] for the Madison Natural Gas Company Limited, were in general agreement with the estimates made by Hume in respect to the particular fields in which their companies were interested. All the above-mentioned geologists expressed their opinion that future exploration and drilling would develop further substantial reserves of gas.

John D. Galloway[7], Executive Vice President of California Standard Company, referred to the development of the gas reserves in the State of Oklahoma and concurred in the submission made by Link.

Stanley J. Davies[8], a geologist with extensive experience in Alberta, called by the City of Calgary, emphasized the factors of availability and recoverability affecting any practical consideration of the estimates of the reserves of gas in place. He pointed out that areas having existing and proven reserves may be located distant from centres of population and possible pipe lines. The rate of withdrawal of gas in any area may be restricted by formation characteristics such as porosity and pressure. Gas produced in oil fields may be required for maintenance of pressure during the period of oil production. He felt that in determining the reserves required to meet the future demands of Alberta consumers, the Commission should take into account only reserves established in areas for which production records are available.

Frank McMahon[9], President of the Peace River Natural Gas Company Limited, and Pacific Petroleum Corporation Limited, testifying on behalf of a group interested in transmitting gas to the City of Vancouver and the Pacific Northwest, stated that there are vast potential reserves of natural gas in the Province, and transmission of gas without the province would only be feasible and possible when the potential reserves had been developed to the extent necessary to justify pipe line construction. He indicated that his group based its plans on the development of additional reserves over and above the present existing and proven reserves.

(1) Tr. Vol. 16
(2) Tr. Vol. 5, 8
(3) Tr. Vol. 5, 8
(4) Tr. Vol. 4, 8
(5) Tr. Vol. 2, 8
(6) Tr. Vol. 19
(7) Tr. Vol. 9
(8) Tr. Vol. 21, 22
(9) Tr. Vol. 24

He referred to the exploration work presently being carried on by his group throughout the province generally and particularly in the northern and north-western sections of the Province.

Dr. G. Govier[1], a member of the Petroleum and Natural Gas Conservation Board, outlined to the Commission the prevailing policy of the Board relative to conservation of natural gas. He stated that in the case of dry gas the policy of the Conservation Board is to permit production at reasonable rates for any reasonable use. In the case of wet gas, not associated with oil in the reservoir, the Board requires the recovery of economically recoverable liquid hydrocarbons before disposition of the gas for some reasonably useful purpose. In the case of solution gas, the policy of the Board is to tolerate "reasonable waste" up to the economic gathering volume, to require recovery of liquid hydrocarbons from all gathered gas, and to require effective use of all residue gas. In respect to the gas condensate type of gas, the policy of the Board is to require proof that no economically preventable loss of liquid hydrocarbons would attend withdrawals before permitting the marketing of residue gas.

F. K. Beach[2], of the staff of the Conservation Board, presented statistics on exploratory and development well drilling.

W. C. D. MacKenzie[3], Assistant Manager, Imperial Oil Limited, Western Division, gave evidence before the Commission on the engineering problems involved in the maximum recovery of oil and gas from the Leduc field. He indicated the possible use of gas for pressure maintenance purposes, and discussed the alternatives open to the management and some of the economic factors requiring consideration in each instance.

CONSUMPTION

Official records of the production and consumption of natural gas in the Province were not kept prior to the year 1927. Since that date the records have been kept, first by the Petroleum Division of the Department of the Interior and latterly by the Petroleum and Natural Gas Conservation Board of the province. The record is set out in detail in a later part of this report.

At the request of the Commission, The City of Medicine Hat, the Northwestern Utilities Limited, and the Canadian Western Natural Gas Company Limited, submitted estimates of present and future consumption in respect to their gas systems in particular, and the province generally.

Harry D. Davis[4], City Engineer of the City of Medicine Hat, stated the present rate of consumption for the Medicine Hat-Redcliff area is approximately 4½ billion cubic feet and he estimated the consumption in the year 1959 would increase to approximately 5.6 billion cubic feet.

H. R. Milner[5], President of Northwestern Utilities Limited, and Canadian Western Natural Gas Company, Ltd., the two major distributing companies, presented a statement of the consumption by both of the companies, and the remainder of the Province in the year 1948—37.265 billion cubic feet; and the estimated consumption for the year 1960—70 billion cubic feet.

The estimates for 1960 were based on anticipated growth in population of the cities and towns presently served with natural gas in the the province, the cities and towns that may be added to the present systems and the anticipated requirements of new industries which may be established in the province.

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(1) Tr. Vol. 21
(2) Tr. Vol. 19
(3) Tr. Vol. 8, 20 & 21
(4) Tr. Vol. 1
(5) Tr. Vol. 15, 16

D. B. Menzies[1], one of the Commissioners of the City of Edmonton, presented a submission on behalf of the City of Edmonton in which he pointed out that the estimates made by Milner with regard to the Northwestern Utilities for the year 1960 were considered by the City Commissioners to be a minimum estimate. The City Commissioners felt that the rate of growth in population and industry in Edmonton would exceed that anticipated by Milner.

Stanley J. Davies[2], representing the City of Calgary, also dealt with the anticipated rate of growth of population and industry in Calgary indicated by Milner. He felt a greater allowance should be made for the requirements of the Canadian Western System than estimated by Milner.

Representatives of the companies organized for the transmission of gas out of the Province filed submissions indicating the amount of gas expected to be purchased by them.

A. R. Dixon[3] and James Walker[4], representing the Northwest Natural Gas Company, indicated that the company expected to require within two years of commencement of operation of the transmission line, 56 billion cubic feet of gas per year at an average of 153 million cubic feet per day, with a maximum daily peak demand of 209 million cubic feet.

Richard Davidson[5], representing the British Columbia Electric Company, a prospective purchaser of gas from the Northwest Natural Gas Company for distribution in the greater Vancouver area, estimated that within five years from commencement of delivery of gas, the British Columbia Electric Company would require approximately 7.3 billion cubic feet of gas per year.

D. D. Morris[6], representing the Consolidated Mining and Smelting Company Limited, a prospective purchaser of gas at Trail, British Columbia, filed a statement showing the possible requirements of the company at Trail to be a minimum of 3 billion cubic feet per year, up to a possible maximum of 5 billion cubic feet per year.

Julian Garrett[7], representing the Western Pipe Lines, the group interested in transmitting gas from Alberta to points in Saskatchewan and Manitoba, including Regina, Saskatoon, Prince Albert and Winnipeg, stated that the requirements of his company within five years from commencement of delivery, would be 26 billion cubic feet per year at an average of 72 million cubic feet per day, with a maximum daily peak demand of 208 million cubic feet.

The Commission called three witnesses with respect to the future consumption of natural gas for industrial purposes in Alberta.

H. Zinder[8], Utility Consultant of Washington, D.C., presented a submission with respect to the importance of natural gas as a determinative force in influencing the location of industry in the United States. Zinder did not attempt to make any investigations with respect to Canadian or Alberta conditions. He directed his efforts to the ascertaining of actually experienced or probable changes in industrial location, as contrasted to possible changes, in the United States only. He pointed out his study necessarily was based on published data or qualitative information available since that date. Zinder stated:

> "it would appear that the earlier economic history of the United States was conditioned in part by the location of certain key materials, particularly iron ore and coal and to a lesser extent natural gas, in the Appalachian area; at this stage, industrial ori-

(1) Tr. Vol. 25
(2) Tr. Vol. 21, 22
(3) Tr. Vol. 9 to 13, 21
(4) Tr. Vol. 11, 12
(5) Tr. Vol. 20
(6) Tr. Vol. 13
(7) Tr. Vol. 12 to 14, 19
(8) Tr. Vol. 17, 18

> entation was also affected by the fortunate location of the Great Lakes. Up to 1939, there was no noticeable evidence that natural gas in the new south-western fields had by itself exerted an appreciable attractive force upon industry. Since that time, the Far West, the Southeast and the Southwest have grown proportionately more rapidly than the rest of the country. With the possible exception of Texas, this growth has been of such a nature that it cannot be attributed to local availability of natural gas supplies."

Zinder concluded that the most important economic factors determining location of industry, in decreasing order of their significance are—(a) market considerations; (b) labor costs; and (c) raw materials including fuel considerations. He stated:—

> "Only in a relatively few industries, such as the chemical and synthetic rubber industries in Texas, is there reason to assume an affinity to the source of natural gas; it appears that even in these cases other factors have been more important. Generally, only in those individual (and infrequent) cases where no other essential fuel resources are economically available, or where all other alternative factors for plant location are well balanced, will the local availability of natural gas be the determinative factor in the location of an industry or of a particular plant."

J. R. Donald[1], an outstanding Canadian Chemical Engineer of Montreal, reviewed the possible chemical industries, requiring natural gas as a raw material and a fuel, suitable for location in Alberta. Donald emphasized that Alberta occupies a unique position in the Canadian economy in that it is the only part of Canada which has natural gas and petroleum in substantial quantities, and that it seemed to follow that, unless other sources of these products are found in Canada, there is bound to be a development of industries based on these products in Alberta. The fact that natural gas can also provide electrical power is a further attractive force for such industries. He forecast a rapid expansion in Canada's population and in markets in Canada, and in addition a rapid expansion in the population of Alberta, with a growing local market.

Donald pointed out that the chemical industry based on the use of gas and oil and byproducts thereof, now known as the petro-chemical industry, was a new and growing industry. Technical processes are in a period of development and there is a growing market demand for the products of such industries in Canada, in addition to a possible export market to be developed as progress is made. He dealt specifically with a number of possible industries and suggested the provision, in the estimates of future consumption of gas in the province, of a substantial allowance for the possible requirements of such industries, both as to gas as a raw material and for fuel and power.

The Research Council of Alberta prepared a submission, presented by W. A. Lang[2]. The submission emphasized the importance of natural gas as a source of power, pointing out that gas can be efficiently converted into electrical or mechanical power by either large or small power-producing units. A suggestion was made as to the possible requirements of gas for electrical power purposes, based on the anticipated growth of the population and industry in the province. The submission further dealt with the importance of gas as a source of synthetic fuels and organic chemicals and referred to experimental data now accumulated in respect to processes developed, though not yet commercially adopted. Lang pointed out that the quantity of natural gas which can be utilized in the production of industrial chemicals is not great in comparison to the amount used for domestic and commercial heating or that would be used for the manufacture of synthetic liquid fuels. Nevertheless, natural gas is of major importance to the chemical industry, because of the versatility of hydrocarbon conversion pro-

(1) Tr. Vol. 23
(2) Tr. Vol. 19

cesses, and of the wide variety of chemicals which can be made from the constituents of natural gas. Markets for many of the chemical products are limited but for others they are large.

The submission further dealt with the advantages of natural gas as an industrial fuel, due to its high calorific value and the ease with which combustion can be controlled. Lang emphasized the desirability of gas for these purposes was dependent in large measure on the assurance of uninterrupted and ample supplies for the life of the plants erected in connection therewith. He concluded reserves of other fuel apart, an ample, dependable and cheap supply of natural gas, considered adequate to meet the requirements in the future of expanding population and of an expanding industry, is an asset of first importance to the province and one likely to contribute substantially to its economic development.

GENERAL REPRESENTATIONS

In general, the submissions made by individuals as such, the officers of associations on behalf of their members, and the representatives of the cities, towns and municipalities in the province, expressed the view that the present and future needs of the people and industries of the province for a period of not less than 50 years should be fully assured before consideration be given to any application for transmission of gas out of the province for sale in other localities either in Canada or the United States. All the witnesses expressed concern that no steps be taken which would endanger the supply of gas to the people of the province as a convenient and low-priced fuel and as an incentive for the establishment of new industries and businesses in the province.

The submissions summarized above are those made by representatives of cities, towns and municipalities, namely Thos. E. Garside[1], Secretary of the Union of Alberta Municipalities; D. B. Menzies[2], Commissioner of the City of Edmonton; Mayor William M. Rae[3], and Alderman Earl W. Smith[4], of the City of Medicine Hat; and the representatives of industry, namely, Norman W. Meldrum[5], of the Dominion Glass Company Limited, Medicine Hat; Thomas Murray[6], on behalf of the Medicine Hat Branch, Canadian Manufacturers' Association; John F. Dower[7], on behalf of the Edmonton Chamber of Commerce; August J. Maure[8], on behalf of the Alberta Branch of the Canadian Manufacturers' Association.

W. A. Austin[9], submitted a brief on behalf of the towns of Innisfail, Oilds and Didsbury, and the villages of Penhold, Bowden, Carstairs, Crossfield, and Airdrie. F. Johns[10], Mayor of the town of Leduc, submitted a brief on behalf of that town. Both Austin and Johns concurred in the views expressed above with the addition thereto, that before permission is granted to export natural gas outside the province, communities not now served with natural gas in the province, be adequately served and be most carefully protected for their future requirements.

Submissions on behalf of the cities of Lethbridge, Edmonton, and Calgary, dealt with the investment of consumers in Alberta in appliances and installations for transmitting and distributing gas. W. D. Trotter[11] called by the City of Calgary, estimated that in an average home, the investment in the whole of the heating equipment including gas burners and auto-

(1) Tr. Vol. 7
(2) Tr. Vol. 25
(3) Tr. Vol. 1
(4) Tr. Vol. 1
(5) Tr. Vol. 1
(6) Tr. Vol. 1
(7) Tr. Vol. 7
(8) Tr. Vol. 7
(9) Tr. Vol. 7
(10) Tr. Vol. 7
(11) Tr. Vol. 21

matic controls would approximate $1100.00 at 1948 prices. Stanley J. Davies[1] pointed out that new homes and apartments being built were designed for the use of gas equipment only, and were financed on the basis of thirty- to forty-year monthly payments. He therefore suggested that provision should be made for an adequate supply of gas for such installations for at least the period of forty years.

Representations were made to the Commission by officers of a number of syndicates and companies organized in Alberta with relatively small capital, subscribed in small amounts by a large number of shareholders residing in Canada. Testifying on behalf of one of such groups, Clifton C. Cross[2] stated that the operations of the smaller companies would be greatly assisted by the provision of a market for gas discovered by the companies during oil exploration work. He pointed out that gas wells had been discovered, but cased and capped because of the lack of market. Without a market for gas the investment in such wells could not be recovered. Wells had been drilled by the companies, which showed indications of commercial gas production, but testing had not been carried out because of the expense involved which could not be recovered due to the lack of market for gas if it had been discovered. Consequently such wells had been abandoned when a gas reserve might have been established. He submitted that with a market for gas, the resulting revenue would increase the funds available to the companies for exploration operations and provide an additional source of return for the shareholders encouraging further investment in oil ventures. The views expressed by Cross were concurred in by Thomas L. Brook[3], K. M. Doze[4] and Henry S. Flock[5], representing further groups of syndicates and companies.

Walter S. Campbell[6], President of the Wainwright Gas Company Limited and long associated with the oil and gas industry in Alberta, made a submission to the Commission in which he reviewed the history of the production and consumption of natural gas in the province and indicated his views as to the future production and consumption of gas. Mr. Campbell expressed the opinion that the gas reserves present and prospective in the province were more than sufficient to supply all possible requirements of the people and industries of the province and allowed a balance for export both to the east and to the west of Alberta.

Submissions were made to the Commission by Vincent A. Cooney[7], Secretary of the Domestic Coal Operators' Association of Western Canada, and William C. Whittaker[8], Secretary and Commissioner of the Bituminous Coal Operators' Association. They emphasized the importance of the coal industry in the economy of the Province. They pointed out that the transmission of gas to Saskatchewan and Manitoba, and to Spokane, Washington, and Trail and Vancouver in British Columbia, would displace Alberta coal now sold in substantial quantities, particularly in Saskatchewan and Manitoba. The loss of such markets to the Alberta coal industry would affect the livelihood of many mine workers and their families and those engaged in the transportation and distribution of coal. In his conclusion, Whittaker stated—

> "We feel that until such time as the citizens in the Province have a full and complete assurance that adequate supplies of gas at reasonable prices will be available for at least 50 years, gas export should not be permitted. We feel also that these assurances should be based on known facts rather than estimates insofar as reserves are concerned, and based on more knowledge with reference to future needs than is now available. If it is then definitely determined that there is an exportable surplus and

(1) Tr. Vol. 21, 22
(2) Tr. Vol. 23
(3) Tr. Vol. 23
(4) Tr. Vol. 21
(5) Tr. Vol. 13
(6) Tr. Vol. 7
(7) Tr. Vol. 24
(8) Tr. Vol. 24

> that its export would be in the best interests of the people of this Province, we could not logically oppose this scheme, regardless of the effect on the industry."

E. H. Keith[1], vice-president of the Alberta Federation of Agriculture, made a submission on behalf of the Federation. In his conclusion, Keith summarized his submission as follows:

> "We should endeavour to be consistent in our trade policies. If it is determined that we have enough gas over and above our requirements, in excess of what may be termed a justifiable period of years, then perhaps we are in much the same position with respect to exporting of gas as we will be in regard to—such commodities as coal, lumber, oil, pulp and paper.
>
> "For the convenience of the Commission we offer the following Summary:
>
> 1. Reserves must be established over provincial requirements for at least fifty years.
> 2. As and when this has been properly established, we are not opposed, in principle, to export.
> 3. If there is no way to conserve gas, it would be better to export it than to waste it.
> 4. If export is allowed, the province should have priority in securing its requirements.
> 5. In estimating these requirements due consideration should be given to the possible development of additional power plants that may be required to more adequately serve rural communities and small or isolated urban centres with electricity.
> 6. Gas exported should be made revenue bearing by means of royalty, tax levies, or by such other means as the Province may have power to employ and that would yield a proper reward for this important resource.
> 7. Gas should be conserved for domestic use as much as possible and encouragement given to Industry to use coal wherever it is convenient to do so.
> 8. Additional gas supplies have resulted through recent exploration for oil.
> 9. It is only through greater development that farmers may expect to obtain the maximum benefits of gas and its by-products.
> 10. Proper care should be exercised so that unnecessary duplication in plants and plant equipment would not result in an unduly high price of these by-products to the consumer."

In his submission to the Commission, H. R. Milner[2], President of the Canadian Western Natural Gas Company Limited, and Northwestern Utilities Limited, expressed the considered opinion of the officials of the companies to the effect that the companies "have never been opposed in principle to the export of natural gas, provided the position of their present and prospective customers in the Province is fully protected as to both supply and price." He stated that people and industry residing and established in the cities and other communities now served or which may be served in the future by the companies, should be able to look forward to an uninterrupted supply of Alberta natural gas at reasonable prices during the foreseeable future, and added—"It is impossible to define the term 'foreseeable future' but in view of the fact that gas has been in use for the past half century, it would not be unreasonable to anticipate a future period of at least an equal length". He pointed out the necessity of some firm arrangement to control any substantial rate increases within the Province, as a result of the influence of prices established for gas exported from Alberta. In this connection he pointed out the advantages accruing from the Alberta companies constructing and operating and either owning or having a dominating interest in an Alberta pipe line gathering system, which could be used, not only for export purposes but to reinforce the supplies to various Al-

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(1) Tr. Vol. 25

(2) Tr. Vol. 15, 16, 27

berta communities. The operation of such a system would be of service in the establishment of a price differential in favour of provincial use as against export use of gas. He pointed out that from every point of view, in his opinion, it was most essential that, in the event of export, the natural gas transmission system now existing and to be built, be tied together as closely as possible, both financially and physically.

Milner, under cross-examination, dealt at some length with the matter of providing further reserves and supplies of gas for the Canadian Western System. He pointed out that the Turner Valley field would not be able to supply the growing daily peak load demand of the Canadian Western System and that it was essential that new reserves be arranged for in the near future.

Stanley J. Davies[1], appearing for the City of Calgary, outlined the effect of recent legislation on the consumers' price in the City of Calgary and the Canadian Western System generally. It was pointed out that the enactment of the Natural Gas Utilties Act in 1944, providing for the fixing of the well-head prices for gas, by the Natural Gas Utilities Board, resulted in an increase in price to the Canadian Western Company for gas supplied to it at Turner Valley, from 7¾ cents to 9 cents in January, 1947; and from 9 cents to 10¾ cents in September, 1948. Davies anticipated that despite the increased volume of gas transmitted and distributed by the Canadian Western Company, the latter increase in the well-head price would, in part, at least, be reflected in an increased price to the consumers.

Davies submitted that the well-head prices offered by the exporting companies in their tentative contracts filed, would necessarily be reflected in a further increase in the well-head price in the fields from which gas would be available for the Canadian Western System and that this, in turn, would in part at least if not in its entirety, be reflected in increased prices to consumers. Davies contrasted the situation affecting consumers of the Canadian Western System to consumers served by the Northwestern Utilities Limited, and pointed out that, because of the fact that the Northwestern Utilities Limited is the owner of the wells and gas in place, changes in the well-head price were not applicable to that system and the possibilities of increase in price to the consumers was restricted to increases in costs of transmission and distribution only.

The prospective purchasers of gas for transmission outside the province, at the request of the Commission, made submissions outlining the possible benefits to the Province of Alberta generally, as a result of the completion of the pipe lines and the purchase by them of the natural gas produced in the province. Some of the benefits referred to by the officials of the Northwest Natural Gas Company[2] were as follows:

The cost of initial construction in Canada will be in the neighborhood of 40 million dollars. Annual operating expenditures in Alberta will be approximately one million dollars for wages and salaries. Exporting gas will not hinder, but will encourage, industrial expansion in the Province, because of the increase in the proven reserves due to the development following upon an assured market for gas. Royalties will be payable to the producers and to the Government of the Province of Alberta. Taxes will be payable in substantial amounts on real property, by way of income tax on the earnings of the company and on the holders of the securities issued by the company. The development of additional reserves will be of benefit to the cities of the Province and the pipe lines will provide a service for additional communities within the Province. Reference also was made to the need of a pipe line to the Pacific Northwest as a defence measure, and the benefits to be derived because of the payment to Canada of American funds as an aid in solving the Foreign Exchange problem.

(1) Tr. Vol. 21, 22

(2) James Walker Tr. Vol. 11, 12

The position taken by the company is summed up in its submission filed in the words—

> "The Company recognizes and subscribes to the principle that the present and foreseeable natural gas requirements of the people of Alberta must be assured and have priority over exports; the company will not enter into the business of distributing natural gas to Alberta consumers, but when distributing companies require gas and it is economically feasible, the company will supply gas to them so they can assure continued service".

Frank McMahon[1], on behalf of Pacific Petroleums Limited, and associated companies interested in transmitting Alberta gas to the City of Vancouver and the Pacific Northwestern States, emphasized the advantages of a wholly Canadian route for such a pipe line. He referred to the large initial expenditure in Canada and the greater annual earnings accruing from transmission charges in Canada. He pointed out the advantages of royalty and tax payments to the Province, together with the added incentive to general oil and gas development in the Province.

Julian Garrett[2], on behalf of Western Pipe Lines submitted that the benefits accruing to Alberta as a result of the completion of the transmission line from Alberta to Manitoba would be as follows:

A market would be provided for the natural gas in fields which have been developed but for which there is no market outlet at the present time. The owners of the gas rights in these fields will have an opportunity of realizing on the very costly exploration entered into by them. Construction of the gathering and transmission systems in Alberta would involve the spending of many millions of dollars for labor and materials. Several million dollars annually would be spent in Alberta for the purchase of natural gas. Many communities in Alberta cannot now be economically served with natural gas and could be served from the company's gathering and transmission lines. The operation of the wells, field lines and transmission systems would provide employment for many persons and the payment annually of considerable sums for operating materials and supplies.

Garrett further submitted that in the event a decision should be reached that the exportable surplus of natural gas is sufficient only to supply the requirements of one or other of the proposed applicants for transmission of gas outside the province, that in the interests of Canada, the Western Pipe Lines be supplied in priority to the Northwest Natural Gas Company.

J. L. Phelps[3] appeared before the Commission on behalf of the Province of Saskatchewan and the Saskatchewan Power Commission. Phelps stated that few questions are of more fundamental importance to the economic life of any region than its source of heat, power and light. The Government of Saskatchewan is therefore anxious that as a first charge on the natural gas available for export from the Province of Alberta, it be utilized to provide abundant fuel and energy to the people of Western Canada and especially to those sections of the Prairies whose resources of coal, gas, petroleum and hydro-electric power sites as well as uranium may be integrated for the benefit of the area as a whole.

Phelps stated that fuel for industrial purposes and for the generation of electrical energy is being required in ever-increasing volume in the Province of Saskatchewan. Due to the absence of hydro-power sites in the vicinity of the populated areas, Saskatchewan has already made a start on the conversion of its electric generating stations to the use of gas for fuel. All its main gathering stations in Saskatchewan can be converted as soon as adequate supplies of natural gas are available at the principal generating points. He referred to the possi-

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(1) Tr. Vol. 24

(2) Tr. Vol. 12, 14, 19

(3) Tr. Vol. 23

bility of the development of the gas resources of Saskatchewan and the usefulness of a pipe line system in integrating the use of the production in the area as a whole, it being desirable that Alberta gas be made available to the Prairie area today in order that Alberta in turn may, in the future, benefit from the development of Saskatchewan's gas resources.

The Honourable J. S. McDiarmid(1), Minister of Mines and Natural Resources of the Province of Manitoba, filed a submission with the Commission. In his submission, the Honourable Mr. McDiarmid stated that he hoped the transmission and distribution of natural gas to the other Prairie Provinces would be given priority over other possible export markets. The export of natural gas from Alberta to the other Prairie Provinces would assist in the creation of those conditions which will permit the two remaining Prairie Provinces to use their domestic resources to the full. This will, in turn, assist Alberta, because it is an accepted general principle that territorial specialization, permitting regions to produce those commodities which their resources are capable of producing most effectively, raises the standard of living of the people of the whole area. New developments which will result if the other Prairie Provinces are permitted to import natural gas, will undoubtedly benefit Alberta, through an increased demand for more of the services and more of the consumer goods that Alberta has supplied in the past. It will stimulate all commercial and industrial enterprises serving Western Canada that are now centred in Alberta.

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(1) Tr. Vol. 25

PART I

INTRODUCTION

I. THE ORIGIN AND NATURE OF NATURAL GAS

Geologists agree that natural gas is formed from organic (i.e. plant and animal) materials. There is no certain explanation of the process of transformation. The generally accepted theory is that the organic materials become imprisoned in the earth's crust and, under the influence of heat and pressure, they decomposed to form natural gas and/or liquid petroleum. Under favourable conditions these materials were trapped and held in the rock reservoirs.

Natural gas, as it occurs in the ground, is a mixture of gases. Most of these gases are hydrocarbons (i.e. compounds of carbon and hydrogen). Some gases of the 'methane' series are listed in the following table:

Name	Formula	Boiling Point	Normal State
Methane	CH_4	—161.4°C	gas
Ethane	C_2H_6	— 88.3	gas
Propane	C_3H_8	— 44.5	gas
Butane	C_4H_{10}	+ 0.6	gas
Pentane	C_5H_{12}	36.2	liquid
Hexane	C_6H_{14}	69.0	liquid
Heptane	C_7H_{16}	98.4	liquid
Octane	C_8H_{18}	124.6	liquid

Non-hydrocarbon gases which may occur in natural gas include nitrogen, hydrogen sulphide, carbon dioxide and helium. The composition of natural gas varies considerably from field to field, and even within the same field. Some analyses of samples of Alberta natural gas are given below:

		Princess (Madison)	Turner Valley	Viking Kinsella	Leduc D3	Pincher Creek
Methane	%	61.56	79.99	92.84	69.56	75.90
Ethane	%	5.06	7.91	1.77	16.57	3.35
Propane	%	2.12	6.56	0.81	6.61	1.07
Butanes	%	1.10	3.49	0.33	1.90	0.66
Butanes Plus	%	0.52	2.09	0.14	0.56	0.36
Carbondioxide	%	10.80	—	0.00	0.20	4.80
Oxygen	%	0.31	—	—	0.40	9.20(H_2S)
Nitrogen	%	18.44	0.05	4.11	4.00	4.60
B.t.u/cf		873	1153	1062	1228	930

Methane is the hydrocarbon present in greatest volume; followed by ethane, propane and the heavier hydro-carbons. The non-hydro-carbons may be extracted as impurities (i.e. "sour" gas containing sulphur may have to be "scrubbed" to make it "sweet" for use) or removed for individual utilization (e.g. carbon dioxide and helium).

The quantity of natural gas is measured in cubic feet, or thousands of cubic feet.[1] However the volume of a unit weight of gas is dependent upon the pressure and temperature of measurement. Consequently, it is necessary to specify the temperature and pressure at which the gas is measured, e.g. 14.4 p.s.i.a. (pounds per square inch absolute) and 60° Fahrenheit.

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(1) The following measures are used to designate quantities of gas:
Mcf.— 1,000 cf.—1 Thousand cf.
MMcf.— 1,000,000 cf.—1 Million cf.
MMMcf.— 1,000,000,000 cf.—1 Billion cf.
MMMMcf.—1,000,000,000,000 cf.—1 Trillion cf.

Natural gas has two significant properties. First, when burned it yields heat. The unit for measuring heat is the British Thermal unit, (B.t.u.), which is the amount of heat required to raise the temperature of 1 pound of water by 1 degree, Fahrenheit. The heat value of Alberta natural gas may range from 850 to 1200 B.t.u. per cf (14.4 p.s.i.a. and 60°F.). The heat value of Alberta coal, which also varies with the composition of the coal may lie between 8,000 and 14,000 B.t.u. per pound. One Kilowatt hour of electrical energy has a heat value of 3412 B.t.u. Second, when processed, a wide variety of chemicals can be made from the hydrocarbon constituents of natural gas. This subject is dealt with later in the Report.

Natural gas as produced from the well may be divided into two separate categories: 1. dry gas, and 2. wet gas[1].

1. **Dry gas** is defined as natural gas which does not contain an economically recoverable content of liquid hydro-carbons (propane, butanes and heavier hydro-carbons) and which usually is not associated in the reservoir with commercial quantities of liquid petroleum (i.e. crude oil).

2. **Wet gas** is defined as natural gas which contains an economically recoverable content of liquid hydro-carbons and which may or may not be associated with commercial quantities of liquid petroleum in the reservoir. Wet gas may be further classified as follows:

(a) Wet gas not associated in the reservoir with commercial quantities of liquid petroleum.

(b) Wet gas associated in the reservoir with liquid petroleum, the liquid petroleum existing as a distinguishable liquid phase (e.g. Princess; Turner Valley crude area; Leduc). This gas may be either—

i. solution gas, or

ii. gas-cap gas (e.g. Turner Valley gas-cap area; and Leduc D3 gas-cap area)

(c) Gas-condensate gas, or wet gas produced from a so-called "gas-condensate" type reservoir.

The terms "solution gas", "gas-cap gas", and "gas condensate gas" may require further explanation.

"Solution Gas" is gas which, under reservoir conditions, exists in solution with the liquid petroleum. Depending upon the reservoir conditions, liquid petroleum in the reservoir may have dissolved in it anywhere from less than 100 to more than 1000 cubic feet of natural gas per barrel of liquid. (e.g. Redwater has a low saturation; Leduc has a high saturation gas content). This gas is therefore produced unavoidably along with the liquid petroleum.

"Gas-Cap-Gas" is gas which, under reservoir conditions, overlies the liquid petroleum. Since this gas is physically separated from the liquid petroleum in the reservoir, it need not be produced along with the liquid petroleum.

"Gas-Condensate Gas" is a term which will be used here to describe the gas produced from a gas-condensate reservoir. A gas-condensate reservoir is one in which the hydrocarbon fluids, both those normally liquid and those normally gaseous, exist in the reservoir in a single phase; and from which a volatile light coloured hydrocarbon liquid may be recovered. The gas-to-liquid ratios may range from below 10,000 to more than 100,000 cu. ft. per barrel, (e.g. Jumping Pound and Pincher Creek are tentatively classified as gas-condensate fields).

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(1) The following paragraphs are drawn from the statement presented to the Commission by Dr. George W. Govier, Petroleum and Natural Gas Conservation Board, "The Policy of the Petroleum and Natural Gas Conservation Board with respect to the Production and Disposition of Gas". Tr. p. 1949

II. GEOLOGY AND NATURAL GAS

The Area of the Sedimentary Basin

The Interior or Great Plains extend from the Gulf of Mexico to the Arctic Ocean. Dr. O. B. Hopkins points out that 1,400,000 square miles or 46 percent of the area of the United States, located largely within the Interior Plains, "is prospective oil territory". In comparison 475,000 square miles or 15 percent of the area of Canada "offers similar prospects".[1]

Small prospective gas and oil areas occur in parts of Eastern Canada and Newfoundland; but the largest area, representing the northern part of the Interior Plains, is in the West. This area reaches from the international boundary, through southwestern Manitoba, southern Saskatchewan, covers most of Alberta, and northeast British Columbia, and extends northward to the Arctic. It is bounded on the east by the Pre-Cambrian Shield and on the west by the Rocky Mountains.

In the region so defined, sedimentary rocks overlie those of the Pre-Cambrian era. Except for small areas in the southwestern and northeastern parts, the whole of the Province of Alberta lies in this sedimentary basin.

The Depth of the Geologic Column

Within the Cambrian, at the base of the Paleozoic column, gas with light oil has been found at Ram River and the other Foothills structures. Ordovician and Silurian beds are not extensively represented in the Plains and Foothills. Large reserves have been established in the Devonian at Princess, Leduc and elsewhere in Southern Alberta. In the Mississippian rocks the Madison or Rundle limestone has produced at Turner Valley, Jumping Pound, Pincher Creek and in widely dispersed areas in the Plains. The Pennsylvanian and Permian formations are absent throughout most of the Plains and Foothills. In the overlying Jurassic sediments gas and oil have been discovered in the southern Plains, from both the basal and upper Ellis sands. The Lower Cretaceous has yielded gas at Lloydminster, Leduc, Redwater, Morinville in the Viking, Bow Island and Sunburst sands. Gas reservoirs have been established in the Upper Cretaceous at Medicine Hat, and have been found east of Leduc.

> "Thus it is evident that gas has been discovered, and reserves have been established in sediments ranging in age from Cambrian through the geologic column up to and including the Upper Cretaceous. The thickness of this sedimentary section ranges from a few feet along the edge of the Pre-Cambrian Shield to thicknesses measured in thousands of feet in the Foothills, and in miles in the Rocky Mountains."[2]

Four broad structural units can be differentiated in south and central Alberta, viz:

(1) The Eastern Plains (geologically, the Alberta Monocline)
(2) The Western Plains (geologically, the Alberta Syncline)
(3) The Foothills Belt; and
(4) The ranges of the Rocky Mountains

West of the Eastern Plains the sedimentary rocks dip into the syncline and are overlain with more recent formations; the depth to oil-and-gas bearing strata is greater, the sedimentary column is deeper, and each sedimentary section is also deeper. The folding and faulting which produced the Rocky Mountains is evident in the Foothills belt. (Fig. 1)

It will be seen from Fig. 1 that certain formations are exposed on the surface of the Province of Alberta. The surface geology is illustrated on the "Geological Map of Alberta,"[3] prepared by the Research Council of Alberta. Dr. J. A. Allan points out that while the sep-

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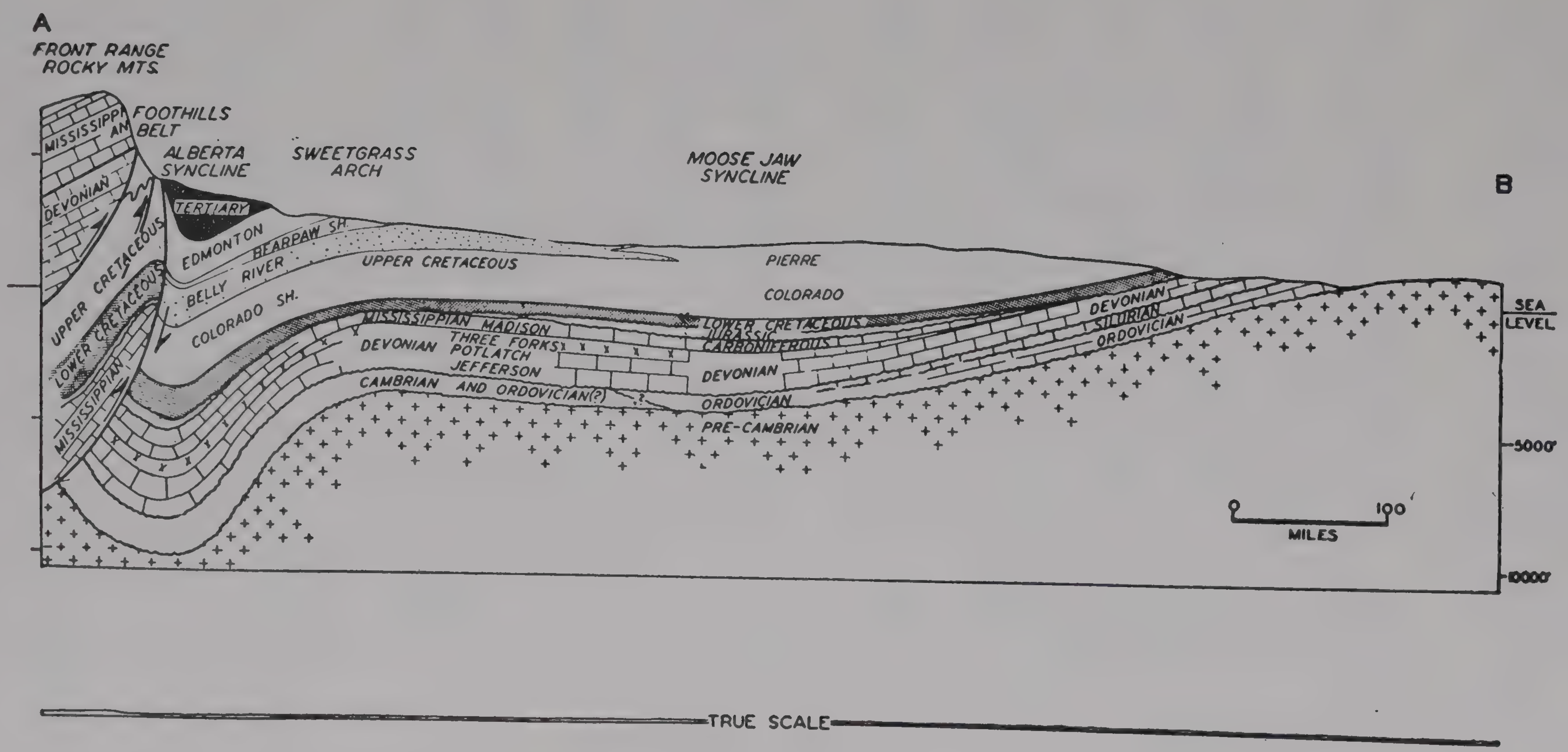
(1) O. B. Hopkins. "The Discovery of the Leduc Field and its Significance". Dec. 18, 1948
(2) T. A. Link Tr. p. 427
(3) J. A. Allan, Geological Survey Division, Research Council of Alberta, 1939.



WESTERN CANADA

arate formations tend to thicken from east to west, it is not possible to fix an average thickness for any formation throughout the Province. "In no one locality are all the formations represented, and in many areas several formations are missing."[1] The absence of any formation may mean either that the sediments were not deposited there or that erosion occurred before younger sediments were deposited.

The Importance of Structure

Sedimentary rock acts like a hard sponge holding the oil or gas in its pores. Oil and gas migrate through porous and permeable rock. Consequently reservoirs of oil and gas are found only under conditions by which these materials are trapped in a particular location. In the past oil and gas have been sought mainly in anticline types of structure. Recent knowledge indicates that petroleum deposits may be found in other types of traps, e.g. lenticular sands, salt domes, faults, reefs, buried hills, wedgeouts and unconformities. Structural conditions in the Plains are strikingly different from those in the Foothills.

Dr. A. D. Brokaw[2] described the structural conditions in the Colorado formation of the southern plains as consisting predominantly of shales of marine origin, commonly including a number of more or less lenticular beds, which have afforded traps. These stratigraphic traps may be of considerable areal extent and often occur along buried shorelines. Their detection by surface studies or geophysical surveys is improbable, and they may be found by more or less random drilling along the probable trend of buried shorelines. This condition, Brokaw points out, is illustrated by the exploration program of the McColl-Frontenac-Union group in the area south and east of Foremost. S. E. Slipper[3] states that—

> ". . . the immediately causal condition of a gas field is usually some change in texture of the gassy horizon, such as, a sand lens, a wedge, an unconformity, etc. though with usually some assisting subdued structural deformation".

In the Foothills, although surface exposures of rocks are more abundant than in the Plains,, the rocks are so folded and faulted that surface indications, along with the results of geophysical surveys, have often proved disappointing. The necessary conditions for gas fields are anticlines, domes, faults and other prominent structural deformations. Dr. G. S. Hume[4] states that most of the southern Foothills folds are considered to be asymmetrical to the east with severe thrust faulting.

> "This type of structure may also be expected to be relatively long and narrow, and since most of the buried limestone masses, from which production comes in the Foothills, are likely to be deep, high pressures are to be expected".

The search for favourable structures has been assisted by recent developments in exploratory techniques, (some of which are still in the experimental stage) "particularly in the use of seismograph, torsion balance, gravimeter and electric well logging equipment. An important new technique recently announced is the air borne magnitometer which is used for rapid geophysical surveys of potential oil and gas areas".[5]

III. RESERVOIR ENGINEERING

The production of gas is an engineering problem varying from well to well and from field to field.

Particular engineering problems arise when gas is found in association with oil. In oil-gas reservoirs the energy required to bring the oil to the surface is provided by gas-cap gas, solution gas, or underlying water. These drives may act in combination and in addition gravitation may be a factor.

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(1) J. A. Allan, General Geology of Alberta, Geology Research Council of Alberta, Report No. 34, 1943, p. 11

(2) A. D. Brokaw Tr. p. 362

(3) S. E. Slipper, Natural Gas Resources of the Province of Alberta, p. 1.

(4) Exhibit No. 3 G. S. Hume and A. Ignatieff. Natural Gas Resources of the Prairie Provinces, 1948, p. 5

(5) Exhibit No. 55 Federal Power Commission—Natural Gas Investigation (Docket No. G-580) Report of Commissioner Nelson Lee Smith and Commissioner Harrington Wimberley, 1948 p. 58

The gas-cap drive is provided by the expansion of the gas in the gas cap, which lies above the oil zone, driving the oil to the area at the bottom of the well where pressure is lower. In this case as the gas and oil come to the surface, the pressure in the reservoir drops slowly and the ratio of gas to oil increases. The total recovery may vary from 30 to 80 percent of the oil in the reservoir.

The solution gas drive is provided by the gas in solution moving to the area of lower pressure at the bottom of the well and carrying the oil with it. The pressure in the reservoir tends to drop rapidly. The ratio of gas to oil rises quite sharply at first and then falls off. Pumping may be necessary in the later stages, and the total recovery may vary from 10 to 40 percent of the oil.

In a water-drive reservoir the recovery mechanism is the movement of the surrounding water toward the area of lower pressure at the bottom of the well, and forcing the oil before it. The pressure in the reservoir tends to drop rapidly at first and then remain fairly constant. The ratio of gas to oil is at first low and then increases. From 50 to 80 percent of the oil may be recovered from a reservoir having an effective water-drive.

Mr. W. D. C. MacKenzie, Assistant Manager, Imperial Oil Limited, Western Division, gave evidence before the Commission on the engineering problems involved in the recovery of oil from the Leduc field.[1] MacKenzie stated that management is confronted with three alternatives; first, pressure will be maintained by water, in which case solution gas must be sold or burned; second, in order to control the decline in pressure some gas should be returned to the reservoir, the balance being sold or burned; and third, all gas should be returned to the reservoir, in which event the gas will not be available for marketing until the greater part of the oil has been withdrawn.

In discussing these alternatives, MacKenzie pointed out that much of the oil in the porous limestone is contained in very small pores or capillaries. A very high pressure differential is required to recover this oil. Injection of water or gas may displace the oil in the large pores but leave the oil trapped in the small pores. It might be possible to recover more oil by allowing some decline in pressure, and marketing or flaring some proportion of the gas which has already done its work of lifting the oil to the surface. He said, "The reservoir engineer also tells us that this study of reserves in the capillary pores versus reserves in large pores is one that cannot be concluded in even a year's time—a great volume of information must be obtained".

The above statement of the problem being dealt with in the Leduc field may not be typical of other fields that will be discovered in the Province, but it indicates the difficulties which must be faced in determining the methods to be followed to obtain the maximum recovery of both oil and gas in solution gas fields.

IV. PRINCIPLES OF CONSERVATION POLICY

This section is taken from the submission of Dr. G. W. Govier, Petroleum and Natural Gas Conservation Board. Mr. A. F. Dixon, Northwest Natural Gas Company, referring to this submission, said, "I can enthusiastically endorse all the policies and plans of the Conservation Commission as they were explained to us today".[2]

Policy With Respect to Dry Gas

The general policy of the Conservation Board is as follows:

1. Complete prevention of production of gas beyond the amount which may be effectively utilized or stored, i.e. complete elimination of waste. Effective utilization may include use

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(1) W. D. C. MacKenzie Tr. p. 1859

(2) A. F. Dixon Tr. p. 2001

of fuel, as chemical raw material, etc. and also used to increase or facilitate the recovery of liquid petroleum in adjacent fields. In the latter connection; however, gas associated with liquid petroleum (after the removal of liquid hydrocarbons) is usually an economically preferable gas for increasing the recovery of liquid petroleum if such gas is available.

2. Prevention of the operation of any well in a manner which may cause damage to the reservoir resulting in a permanent loss of recoverable gas. This is satisfied by good engineering practice, by common sense operation, and by avoiding excessive withdrawal rates. The optimum withdrawal rates are determined by the reservoir conditions, particularly pressure, porosity, permeability, thickness of pay section, extent of pay section, connate water content, etc. The proper rates can be established only after field testing and production.

Summarizing for the case of dry gas, the Conservation Board policy is to permit production at reasonable rates for any reasonable use. Use as fuel, as chemical raw material, etc. will usually prove more economical than use for increasing or facilitating liquid petroleum recovery at nearby oil fields. However, this latter possibility should not be dismissed entirely.

Policy With Respect to Wet Gas

(a) Wet Gas not Associated in the Reservoir with Commercial Quantities of Liquid Petroleum

The policy with respect to fields of this type is to permit production as in the case of the dry gas fields, but to require the recovery of the economically recoverable liquid hydrocarbons before disposition of the gas.

(b) Wet Gas Associated in the Reservoir with Commercial Quantities of Liquid Petroleum

Solution Gas

Production of gas from fields of this type is unavoidable with production of oil. For this case the general policy of the Board reduces to the following:

1. The prevention of excessive "wastage" of gas. Ideally, the Board would prefer no waste of gas, but the Board recognizes—

(i) that produced solution gas aids the lifting of oil from the reservoir and in this sense has undergone some "use".

(ii) that up to a certain volume and/or pressure it may be uneconomical to gather gas which is unavoidably produced with oil. This is the case early in the life of a field, e.g. now at Leduc and Redwater.

For these reasons the Board tolerates a "reasonable waste" of solution gas when such waste accompanies the economic production of liquid petroleum, but not beyond the point where gathering of the gas in reasonably economical.

2. For such solution gas as can be economically gathered, the policy of the Board is to require the removal of the economically recoverable liquid hydrocarbons. The value of recoverable liquid hydrocarbons is usually a major factor in determining the volume and/or pressure at which solution gas can be economically gathered and processed.

3. The solution gas after removal of recoverable liquid hydrocarbons is termed "residue" gas. The policy of the Board is to require complete effective use or storage of this gas. While effective use includes use as fuel, chemical raw material, etc. the Board is particularly concerned in seeing that, when economical and feasible from an engineering viewpoint, part or all of this residue gas be employed to increase the ultimate recovery of liquid petroleum from the reservoir. This may be done by strategic reinjection of the gas into the reservoir to maintain or actually increase the reservoir pressure. The terms "pressure maintenance" and "repres-

suring" are used with reference to such programs involving the injection of gas into a petroleum reservoir for the primary purposes of maintaining or increasing reservoir pressure, and increasing the ultimate recovery of liquid petroleum. Use of gas for pressure maintenance has the effect of deferring the time when it may be used for other, i.e. market purposes.

In the case of solution gas, then, the policy of the Board is to tolerate a "reasonable waste" up to the economic gathering volume, to require recovery of liquid hydrocarbons from all gathered gas, and to require effective use of all residue gas. The Board wishes to point out that use of residue solution gas for pressure maintenance may prove to be attractive from both the engineering and overall economic view in such fields as Leduc and Redwater. This question is now under study by the Board and others. To some extent water may be considered as an alternate to gas for pressure maintenance and the enhancement or development of reservoir "drive". It must be emphasized, however, that conditions may exist in the reservoir which would dictate against the use of water. There is some indication (as yet only an indication), that water may not be as effective as gas for obtaining the maximum economic recovery of oil from the Leduc D3 zone. Should it develop that residue solution gas is attractive physically and economically for pressure maintenance or "secondary recovery" in the Leduc, Redwater and/or other fields, the policy of the Board would be in opposition to the immediate use of this gas for other, i.e. market purposes. Such gas should then be considered as stored, and available for market only after its removal would not prejudice the ultimate oil recovery.

Gas-Cap Gas

Production of gas of this type need not necessarily accompany the production of liquid petroleum. The policy of the Board with respecto gas-cap gas is best illustrated by reference to the Leduc D3 gas-cap. Turner Valley presents a special case and will be referred to separately. The general policy of the Board is as follows:

1. To prevent production of gas-cap gas for market so long as this gas, in the reservoir, is economically aiding in the recovery of liquid petroleum underlying it.

2. To permit production of gas-cap gas for the removal of liquid hydrocarbons so long as the residue gas obtained is returned to the reservoir and so long as the well is not operated in a manner which may cause damage to the reservoir resulting in a permanent loss of either recoverable oil or gas.

The requirement of returning gas-cap residue gas to the reservoir would be Board policy so long as this gas could economically aid in the recovery of the underlying liquid petroleum.

Present practice in Turner Valley is to permit production of gas-cap gas in accordance with the Brown plan and for removal of liquid hydrocarbons and effective use of the residue gas. This plan, inaugurated several years after production from gas-cap wells had started, represents a compromise between true conservation and unrestricted flow from the gas-cap. Such a compromise is required because most of the gas-cap wells were drilled and production started before the engineering concepts of conservation were well developed. Furthermore, many of the Turner Valley wells which are drilled in the gas-cap cannot reach the underlying oil which, because of the dip of the structure, underlies other leases. In such cases the practice of complete conservation is virtually impossible unless the entire field is operated as a unit. The present policy of the Board towards gas-cap production from Turner Valley or from future similar fields is to promote and assist efforts which would lead either formally or informally to the unit operation of the field and then to follow the general "gas-cap" policy as outlined with reference to the Leduc D3 gas-cap.

Summarizing for gas-cap gas, the policy of the Board is to prevent production of gas-cap gas except at reasonable rates for the recovery of liquid hydrocarbons and under circumstances where the residue gas is reinjected into the reservoir. To this end the Board will promote and assist efforts towards the unit operation of a reservoir. Turner Valley represents a special case and should not be considered typical. Gas-cap gas, other than that in Turner Valley, should therefore be considered as stored and available for market only after its removal would not prejudice the ultimate oil recovery.

Policy With Respect to Gas-Condensate Gas

The tentative policy of the Board for these fields is based upon the assumption that they may prove to be of the gas-condensate type with the reservoir fluid present in a single phase. For such reservoirs it has been proven by United States experience that the ultimate recovery of liquid hydrocarbons is greatly dependent upon production methods. Specifically it has been shown that if the reservoir pressure is permitted to drop below a critical value (for a given reservoir fluid) retrograde condensation may occur in the reservoir with a permanent loss of recoverable liquid ranging from approximately 10 per cent to approximately 50 per cent.

The present policy of the Board with respect to gas from the above fields is:

1. To prohibit the production of reservoir fluid pending detailed analyses of samples of the reservoir fluid and determination of the engineering and economic importance of maintaining reservoir pressure.

2. If analyses and study should show no danger of retrograde condensation or no serious economic loss attending retrograde condensation, the policy of the Board would be to treat the field as under classification (a)—"wet gas fields not associated with liquid petroleum", and to permit production for recovery of liquid hydrocarbons and effective utilization of the residue gas.

3. If analyses and study should show danger of retrograde condensation and serious economic loss of recoverable liquid hydrocarbons attending pressure decline below some critical value, the policy of the Board would be to permit the production of reservoir fluid for recovery of liquid hydrocarbons but (if feasible from the engineering and economic viewpoints) to require the reinjection of the residue gas into the field for the purpose of pressure maintenance. This method of operation is often called "cycling" or "recycling" but is essentially pressure maintenance. The effect of this policy would be, as in the case of gas-cap gas, to defer the time when the residue gas from the gas-condensate fields would be available for market.

Summarizing for the gas-condensate type of gas, the policy of the Board is to require proof that no economically preventable loss of liquid hydrocarbons would attend net withdrawals before permitting market of residue gas. In the event of serious loss possibilities, the Board policy would be to require recycling of residue gas, if practical, and thus to defer the time when the residue gas could be marketed.

V. THE OWNERSHIP AND CONTROL OF MINERAL RIGHTS

Ownership

In 1870 the Dominion Government entered into an agreement with the Hudson's Bay Company, whereby the Crown gained possession of the Northwest Territories, including the area now comprised in the Province of Alberta. The agreement provided that the Hudson's Bay Company would retain ownership of about 5% of the lands, including mineral rights, within the fertile belt of the territories. The area allocated to the Hudson's Bay Company was comprised in 1¾ sections in each township, namely section eight, and three-quarters of section twenty-six, with an additional allowance in respect to the townships in which the above sections were covered by water. The Hudson's Bay Company interests still retain the petroleum and natural gas rights in approximately 1,506,000 acres.

The mineral rights, covering large areas in the western provinces, were included in grants of land to the Canadian Pacific Railway Company and other railways. These grants in most part comprised the odd-numbered sections, except sections 11 and 29, in each township in the area bounded on the north by the North Saskatchewan River. It should be noted, however, that in the large area included in the irrigated areas in South Central Alberta, between Calgary and Medicine Hat, the grant to the Canadian Pacific Railway Company comprised all the lands excepting the Hudson's Bay quarters and in this area the Crown is not the holder of mineral rights.

The Commission is advised that the Canadian Pacific Railway Company still retains all minerals in approximately 7,266,279 acres; and 'coal only' or 'coal and valuable stone' in a further 1,391,709 acres. The Calgary and Edmonton Corporation and associated companies still retain the petroleum and natural gas rights in approximately 1,350,000 acres.

Prior to 1887, patents issued for the lands under Homestead and purchase from the Dominion Government included mineral rights in the grant of the patent. After 1887, the grants did not include the mineral rights, with the result that the Crown in the right of the Dominion retained the mineral rights under large areas.

In 1930, the ownership of the natural resources in the Province, including the mineral rights held by the Dominion, passed to the Province of Alberta.

A statement of the acreage comprised in the mineral rights held by the Crown in the right of the Province of Alberta, and the acreage of mineral rights owned in freehold is as follows:

Total area of the province	163,382,400 acres
Area in the Dominion Parks reserved to the Dominion Government	13,434,240 acres
Area in Indian Reserves reserved to the Dominion Government	1,328,090 acres
Held in freehold including railroad grants	16,000,000 acres
Mineral rights held by the Province of Alberta	132,620,070 acres

The officials of the Department of Lands and Mines estimate that in the portion of the Province located south of the North Saskatchewan River, the Crown in the right of the Province, holds the mineral rights in approximately 30,000,000 acres and the mineral rights are owned freehold in approximately 15,000,000 acres.

Leases and Reservations

As at December 31st, 1948, the Crown in the right of the Province of Alberta, had issued petroleum and natural gas leases covering 2,556,083 acres of Crown mineral rights, and in addition petroleum and natural gas reservations covering 23,473,490 acres of Crown mineral rights. The term of the petroleum and natural gas lease, issued by the Crown is for 21 years, renewable for a further term of 21 years so long as the location is capable of producing petroleum and/or natural gas, and is held by the Lessee subject to the terms of the lease and the provisions of the regulations made pursuant to the Provincial Lands Act. The current form of lease, issued since April, 1948, prescribes that the rate of royalty which the Crown will receive during the first term of the lease shall not exceed one-sixth (16 2/3%) of the gross recovery of petroleum in the lands comprised therein. The lease further includes a term as follows:

> "That the lessee covenants, and it is an express condition upon which this lease is granted, that no natural gas, taken from the lands herein described, shall be exported out of the Province of Alberta, by anyone, unless the consent of the Lieutenant Governor in Council has been previously obtained. Upon any breach of this covenant and condition occurring, whether with or without the consent or knowledge of the les-

> see, this lease, in so far as it relates to the natural gas within and under the lands herein described, shall forthwith be terminated, shall become null and void, and shall cease to have any further force or effect and the natural gas within and under the lands herein described, shall thereupon revert to His Majesty, freed and discharged of any interest or claim of the lessee or any other person or persons whatsoever, claiming by, through or under the lessee."

The royalty payable with respect to natural gas obtained from any location covered by a Crown lease is that prescribed in Order-in-Council dated the 28th day of May, 1941, and numbered O.C. 725/41, as further amended on the 12th day of August, 1941, and the 3rd day of May, 1943, and the 29th day of March, 1948. The provision of the said Order-in-Council is as follows:

> "The royalty to be computed, levied and collected on natural gas obtained from every location, acquired under the provisions of the regulations heretofore established by the Dominion of Canada or by the Province of Alberta for the disposal of petroleum and natural gas in Provincial Lands and School Lands consumed for some useful purpose off the location or sold shall be fifteen per centum of the selling price or fair value at the time and place of production, provided that for the purposes of this paragraph each sub-lease shall be deemed to be a location; provided further that in no event shall the royalty to be computed, levied and collected as herein provided be less than three-quarters of one cent per thousand feet (mcf). (O.C. 659/43)."

The rental payable in respect to petroleum and natural gas leases is $1.00 per acre per annum, provided that if the lands comprised in the lease are proven to be gas-bearing only the rental may be reduced under the provisions of Section 11 (e) of the Petroleum and Natural Gas Regulations established by Order-in-Council dated the 29th day of March, 1948, and numbered O.C. 308/48, as follows:

> "(e) (1) A lessee who in the search for petroleum claims to have made a discovery of natural gas that indicates the area to be a natural gas field, and through drilling of wells adequately spaced to the satisfaction of the Minister reasonably delimits the field within the confines of his lease or leases thereby substantiating his claim, shall thereafter pay to the Minister the annual rental of fifty cents an acre payable yearly in advance so long as the location is capable of producing natural gas, provided that a well shall be drilled in the search for oil at a point and to a formation fixed by the Minister before the reduction in rental becomes effective.
>
> " (2) While an adequate market or a market in which the leases may participate is not available the Minister may, upon his acceptance of such facts, further reduce the rental of the location to an annual rental of twenty-five cents an acre.
>
> " (3) Should a discovery of petroleum be made in any subsequent well drilled the provisions of this subsection (e) shall immediately become null and void and the lease shall revert to its original status.
>
> "(f) During the year in which the further reduced rental is accepted by the Minister the lessee shall be relieved from the development requirements of his lease."

The Canadian Pacific Railway Company further advises that of the 7,266,279 acres, some 34,458 acres are now leased by the Company. The Company form of lease, after providing for a drilling commitment, calls for an annual rental of $1.00 per acre per year and the payment of a reserved royalty to the Company of 12½ percent on all products produced and sold from the leased area. The balance of 7,266,279 acres above mentioned, is comprised in petroleum reservations issued by the Company to parties desiring to carry on geological and geophysical investigations on the lands covered in each reservation. The petroleum reservations are issued for a term of one year at a fee of 10½ cents per acre per year and confer the right on the holder of the reservation to apply for and obtain a petroleum and natural gas lease for any part of the area covered by the reservation within the term of the reservation.

It is difficult to obtain evidence with respect to the terms of leases granted by owners in Fee of the mineral rights held by them, but in the main it is generally accepted in the industry that the terms of leases by individual owners of mineral rights, follow closely the terms of the Crown and Canadian Pacific Railway Company leases as to rental and royalty reserved to the Owners in Fee.

Agreements

Apart from the leasing of mineral rights in accordance with the regulations established under the Provincial Lands Act, the Crown in the right of the Province has entered into specific agreements with certain municipalities and companies including the Northwestern Utilities Limited and the City of Medicine Hat and Shell Oil Company of Canada Limited.

Under the terms of an agreement dated the 8th day of June, 1944, the Crown agreed to lease to Northwestern Utilities Limited the lands comprised in the areas under which the Crown holds mineral rights in the Viking and Kinsella fields. The agreement provides that the rental to be paid by the Northwestern Utilities Limited for the lands comprised in the agreement is 33⅓ cents per acre. The payment of 33⅓ cents is relevant only to the natural gas in and under said lands. In the event petroleum in commercial quantities is obtained from drilling operations, then the rental of $1.00 per acre becomes payable. The term of this agreement is for 21 years, renewable for further terms of 21 years, at the option of the Northwestern Utilities Limited.

On the 25th day of September, 1946, the Crown in the right of the Province of Alberta entered into an agreement with the City of Medicine Hat. This agreement likewise provides for the leasing by the Crown to the City of Medicine Hat of lands under which the Crown is the holder of petroleum and natural gas rights in the immediate area of Medicine Hat at a rental fixed in the sum of 33⅓ cents per acre per year.

Another agreement of particular interest is the agreement dated the 13th day of June, 1945, entered into between the Crown in the right of the Province of Alberta and the Shell Oil Company of Canada Limited. This agreement deals with the drilling operations to be conducted in the Jumping Pound area. The preamble of the agreement contains the following:

> "WHEREAS in accordance with its policy of conserving the natural resources of the Province, and avoiding loss of production through waste, the Government of the Province of Alberta has curtailed the production of natural gas and it is anticipated may further curtail and regulate the production of natural gas, particularly where no market therefor exists, and it is not at present in the interests of the Province, the said lessors or the Lessee to drill further wells within the gas area, the boundaries of which can be determined only by drilling; and
>
> WHEREAS the Province and the said lessors have agreed or will be asked to agree to unitize their lands (including all petroleum, natural gas, other related hydrocarbons and associated substances, insofar as the particular Freehold leases and Crown leases include other related hydrocarbons and associated substances, in any and all formations or horizons therein) to the extent of the acreage particularly set forth following their respective names subscribed hereto (hereinafter collectively called "said lands") and to enter into this agreement with the Lessee for the orderly and economical exploration and development of the lands within which may be found

> petroleum and natural gas in order to assure a greater ultimate recovery of petroleum and natural gas;"

The agreement as amended covers 9,558 acres comprised in Crown leases and 8,515 acres comprised in freehold leases, a total of 18,073 acres.

The division of royalty as between the respective lessors including the Crown is as follows:

> "6. **Royalty**
>
> Regardless of the location of any well or wells drilled by the Lessee on the said lands which shall produce petroleum and/or natural gas, each of the Lessors shall, except as in Clause 7 provided, receive from the Lessee royalty computed in the manner and at the rate provided for under his respective lease on that proportion of such petroleum and/or natural gas which bears the same relation to the total production from the said lands as the acreage owned by him subject to this agreement; and such royalty shall be in complete satisfaction of all royalty rights of the Lessors under the Freehold Leases and Crown Leases referred to in this agreement so far as they relate to the said lands."

This agreement is of particular interest in respect to the unit operation of oil and gas fields. It may well serve as a model for future unitization agreements so that natural gas and oil fields of the province may be developed with a minimum of waste in the interest of all concerned.

PART II

THE ALBERTA SITUATION
RESERVES AND CONSUMPTION

I. HISTORY OF EXPLORATION AND DISCOVERY OF OIL AND NATURAL GAS IN ALBERTA

Early Discovery: 1884 - 1908

Discovery of gas in Alberta dates back to 1884, when a small flow of gas was obtained at Alderson. Seepages of gas in the South Saskatchewan River led to drilling in the Medicine Hat area, and small supplies were found as early as 1890. In 1894, the Dominion Geological Survey drilled in the Athabaska area in search for oil in the down-dip of the bituminous sands, but only small showings of gas resulted. A gas well drilled at Pelican (on the Athabaska River) in 1897 caught fire and burned for 21 years. Larger supplies of gas were found in shallow wells at Medicine Hat in 1904; but the principal gas zone in the field was first tapped by a well drilled by the Canadian Pacific Railway in 1908. This date marks the beginning of commercial gas production in Alberta.

Gas Development: 1908 - 1927

A number of significant developments in natural gas production and distribution occurred between 1908 and 1927. Although the large development in distillate production from Turner Valley began in 1924, it is convenient to terminate the period at 1927. After 1927 records of production became more accurate. "No systematic metering of production was undertaken for a long time, but partial metering with estimates of unmetered gas are available from 1927, with improvements in accuracy as time passed".[1]

Development in the Medicine Hat area continued after 1908, and by 1914 some 20 producing wells had been drilled.

The **Bow Island** field was discovered in 1909. Between 1911 and 1921, Canadian Western Natural Gas, Light, Heat, and Power Company drilled 27 wells to serve a pipe line to Calgary. By 1927 this field was beginning to show signs of exhaustion; and it has since been used as a storage reservoir for Turner Valley gas. The Canadian Western developed the **Brooks** field in 1910 to serve the Town of Brooks.

Seepage of gas had been detected in **Turner Valley** in the early years, but the discovery well (Dingman No. 1) was drilled in 1913. "Several productive gas wells were drilled, and in 1921 a combination 6- and 8-inch line was laid from an absorption plant in Turner Valley to Okotoks, where it joined the Bow Island-Calgary 16-inch gas line. The really large development of Turner Valley did not begin, however, until 1924, when Royalite No. 4 well was completed as a large gas-condensate well in the Paleozoic limestone at a depth of 3,740 ft.[2]

Dry gas was discovered in the **Viking** area in 1914, and transportation to Edmonton by pipe line commenced in 1923. At this time there were 9 producing wells in the Viking end of the field, and it was not until 1940 that wells in the Kinsella portion of the field were connected to the line.

Apart from these developments there was little exploratory activity between 1908 and 1927.

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(1) Petroleum and Natural Gas Conservation Board, Annual Summary, Alberta Petroleum Industry 1947, p. 29.
(2) Exhibit No. 3 p. 147

Turner Valley: 1927 - 1946

Following 1927 the situation in Alberta was dominated by Turner Valley; first as a gas-condensate and later as a crude oil field. The 20 years (1927-1946) can be divided into four periods of approximately 5 years each. The discovery of the Leduc oil field initiated a new stage in gas and oil development in the Province.

General Activity: 1927 - 31

The period 1927 to 1931 was one of some activity centering around, but not entirely confined to the development of the gas-condensate area of Turner Valley. The total footage drille din Turner Valley was 590,042 ft.; while 378,947 ft. were drilled in the remainder of the Province. The total footage drilled in the Province was, therefore, close to 1 million feet.

Outside of Turner Valley, additional wells were drilled in the Medicine Hat and Viking fields. Some drilling was done at Wainwright, but the main new development was in the **Foremost** area. A discovery well was drilled here in 1916, but was shut off and later abandoned. Canadian Western Natural Gas, Light, Heat and Power Company commenced drilling operations at Foremost in 1923. The field was connected by an 8-inch pipe line to the Bow Island-Calgary 16-inch line; and since that time has been used to meet peak-load demands for gas in Calgary.

Depression: 1932 - 36

During the depressed years, 1932-36, drilling operations declined. Total footage for the Province was 359,782 ft.; 223,112 ft. in Turner Valley, and 136,670 ft. in other parts of the Province.

The only significant new development was the bringing into production of the **Lloydminster No. 1** well in 1934.

Turner Valley Crude Oil: 1937 - 41

Crude oil was discovered in the west flank of Turner Valley in 1936. Previously wet gas had been drawn from gas-cap wells for the naphtha content. The gas produced was greatly in excess of market requirements and about one trillion cubic feet is estimated to have been wasted. The rapid depletion of the field was recognized as early as 1930 but it was not until after the discovery of oil lower down the structure on the west flank that a marked decline in withdrawals of the gas from the gas-cap took place. This was effected partly by voluntary conservation measures and partly by measures enforced by the Conservation Board. Subsequent developments have been in the crude oil zone.

The discovery of crude oil in 1936 gave an immense stimulus to activity in Turner Valley. Drilling rapidly expanded and footage drilled in the Valley reached a maximum of 377,860 ft. in 1941. The Turner Valley development, along with some general improvements in economic conditions and the outbreak of war, contributed to increased activity in other parts of the Province. In the period 1937-1941, total footage drilled was 1,890,600 ft. Of this 1,504,795 was drilled in Turner Valley, and 385,805 ft. in other parts of the Province.

Drilling began in the **Vermilion** area in 1937; and significant exploratory efforts were made in the foothill areas of **Brazeau, Ram River, Clearwater** and **Pincher Creek.**

The War and Decline of Turner Valley: 1942 - 46

The war period, 1942-46, coincided with the second decline of Turner Valley, this time as a crude oil field. There was a marked expansion of activity elsewhere in the Province. In the five years, footage drilled in Turner Valley totalled 1,096,511 ft.; but annual drilling declined from 348,772 ft. in 1942 to 77,997 ft. in 1946. Outside of Turner Valley, footage drilled totalled 1,444,318 ft. and increased from 160,915 ft. in 1942 to a high, for the period, of 384,-

388 ft. in 1945. As the depth of the wells in Turner Valley generally is greater than in areas of exploration in the Plains, the shift of activity from Turner Valley to other areas is more clearly represented by the number of wells drilled. Between 1942 and 1946, 138 wells were drilled in the Valley; 546 (110 in 1945) were drilled in other parts of the Province. The extent to which oil and gas development has been concentrated in Turner Valley is evident from the fact that up to and including 1941, 2,433,271 ft. had been drilled in the Valley; 1,433,663 ft. elsewhere in the Province. The comparative figures at the end of 1946 were Turner Valley 3,529,782 ft.; all other drilling, 2,877,981 ft.

Reference to the main developments outside Turner Valley, initiated during the period 1942-46 follows:

A substantial number of wells were drilled in the vicinity of Medicine Hat, extending the recognized area of the field.

McColl-Frontenac Oil Company Limited, either alone or jointly with Union Oil Company of California, carried out a program of exploratory drilling in the Pakowki Lake region of southeastern Alberta. It is understood that this program, although initially undertaken in search of oil, was continued with natural gas as a primary consideration. In view of the oil situation, production of gasoline by syntheses of natural gas appeared a possibility. The activities of McColl-Frontenac and associates led to the discovery of four, apparently distinct, dry-gas fields: **Pendant d'Oreille, Manyberries, Black Butte** and **Smith Coulee.**

With similar concern for the possible use of natural gas as a source of synthetic gasoline, Imperial Oil Limited commenced drilling operations in the **Kinsella** portion of the Viking-Kinsella field, and in the **Provost** area.

California Standard Company embarked on an extensive program of drilling in the **Princess** area, later (after 1946) extending into the **Foremost, Dunmore** and **Brooks-Bantry** areas.

Drilling began in 1946 in the **Elk Point** area, by Anglo-Canadian and Home Oil Companies, which led to the discovery of salt as well as gas.

The Dominion Government obtained local sources of gas to meet their requirements at **Wainwright** and **Suffield.**

The Town of **Athabasca** was supplied with gas as a result of drilling in the vicinity.

Further exploratory drilling was initiated by Home Oil in the **Brazeau** area. The discovery well in the **Jumping Pound** field was drilled by Shell Oil in 1944.

At the end of 1946, there had been drilled in Alberta 1564 wells for oil and/or gas. The Petroleum and Natural Gas Conservation Board has classified these as 590 oil wells, 274 gas wells, and 700 dry holes.

Leduc-Woodbend and Redwater: 1947 and 1948

The discovery of the Leduc oil field in February, 1947, and the subsequent discovery of the Redwater field in October, 1948, changed the direction of, and gave impetus to exploration in the Province.

Total footage drilled in 1947 increased to 882,358 ft. In 1948, the footage drilled almost doubled to reach 1,701,636 ft.; an amount greater than the footage drilled in Turner Valley in any five years.

The Petroleum and Natural Gas Conservation Board has classified the wells as follows:

	1947	1948
Oil Wells	116	202
Gas Wells	33	20
Dry Holes	75	133
TOTAL	224	355

The major part of this development took place in the Leduc-Woodbend area. However, significant developments were occurring at such widely separated locations as **Hanna, St. Paul, Pouce Coupe, Lloydminster,** and **Pincher Creek.**

II. METHODS OF ESTIMATING GAS RESERVES

Gas occurs in fields or reservoirs within porous rock formations. In reference to a particular field the term "gas reserve" may refer to either (a) the quantity of gas present in the reservoir, i.e. gas in place; or (b) the quantity of gas which may ultimately be withdrawn from the reservoir, i.e. recoverable gas. It is important to recognize that the two quantities are not necessarily, and in practice are not, the same. The **recoverable gas** is always less than the quantity of **gas in place.**

In **dry gas fields** the two established methods of estimating reserves in place are known as (a) the production pressure-decline method, and (b) the volumetric or area-porosity method.

Production Pressure-Decline Method

The U. S. Federal Power Commission[1] describes the production pressure-decline method as follows:

> "The production pressure-decline method considers the producing horizon or reservoir as a gas container of constant volume.
>
> "By knowing the pressure decline resulting from a certain volume of production, the amount of gas contained in the reservoir at any given pressure may be determined. Extrapolation of this relationship to an assumed abandonment pressure yields an estimate of the reserves of gas which may be recovered.[2]
>
> "Since this method requires a reservoir of constant volume, the method is not applicable if there is any substantial water encroachment into the reservoir as the gas is produced. That is, the size of the "container" will become smaller. It is also necessary to have an accurate measurement of pressure at a sufficient number of wells so that a weighted average pressure for the reservoir as a unit may be determined. Generally, the field must have produced at least 10 percent of its original volume of gas before the use of the pressure-decline method can be considered reliable. As the field becomes more nearly depleted, the accuracy of this method increases.
>
> "Where the production pressure-decline method can be used, it is generally considered to be a more accurate procedure for estimating reserves than the volumetric method".

G. S. Hume[3] refers to the pressure-decline method in these terms:

> "By far the most reliable estimates are those of the producing gas fields where drilling has indicated the extent of the area from which production will occur and where from time to time during production the pressure has been carefully recorded in relation to the volume of gas produced. The relation between the pressure-decline and the production gives an accurate method of appraisal and the reserves here calculated by this method are considered as proven. These include such fields as Turner Valley, Viking-Kinsella-Fabyan, Bow Island, Foremost, Brooks and Vermilion. Medicine Hat is also included although the records are not as complete as for the other fields."

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(1) Exhibit No. 55 p. 43

(2) If atmospheric pressure is assumed, extrapolation yields estimates of the total gas in place.

(3) Exhibit No. 3 p. 2

From the evidence before it, the Commission concluded that the production pressure-decline method can provide highly accurate estimates of gas in place; but, in practice, the accuracy of the results obtained depends upon the adequacy and accuracy of the available data on production, pressure throughout the field, and water encroachment. If the available information on these factors is incomplete or inaccurate the reliability of the method may be greatly reduced, and estimates may either under- or over-state the quantity of gas actually in the reservoir.

The Volumetric, or Area-Porosity Method

The U. S. Federal Power Commission[1] describes the volumetric method as follows:

> "The volumetric method involves first a determination of the net pore space occupied by the gas in the reservoir sands. The factors used are the number of acres of gas bearing sand, its average thickness, its porosity, and the amount of connate or interstitial water. These values are determined from data obtained from the drilled wells. From well-log information, including electric logs, contour maps of the structure are made. From these the areal extent, or the number of productive acres, is determined. Electric logs are also used to gauge the thickness of the pay sand. From such information isopachous maps are constructed from which the weighted average thickness of the sand may be ascertained. When the various factors have been determined as a result of these studies of the reservoir, the determination of the net pore volume is merely that of applying a mathematical formula.
>
> "The net pore space obtained is the volume of gas in the reservoir under reservoir pressure and temperature. To express this volume in terms of standard conditions of temperature and pressure, the average temperature and pressure of the reservoir must be ascertained. With these data the number of standard cubic feet of gas may then be calculated".

Hume[2] refers to the volumetric method in these terms:

> "There are many areas where gas wells have been drilled but from which no production has been taken. In these the pressure-decline method, based on the drop in pressure in relation to the gas yield, obviously cannot be used. It is, therefore, necessary in such cases to compute the amount of gas contained in the reservoir on a volumetric basis. This is the porosity-area method. In it the extent of the possibly productive area is estimated from such wells as have been drilled and from what has been learned concerning the geological conditions such as structures, character of the reservoir beds and level of gas-oil, gas-water interface. The other factors which must be known from drilling or be estimated are thickness of the productive zone, its porosity and connate water content, the compressability of the gas and the reservoir temperature and pressure. The reservoir temperature and pressure are a matter of record from wells drilled and hence, if properly taken, are accurate. The effective thickness of the sand, its porosity and connate water content are much more difficult to estimate correctly, since each may vary according to changes in the sedimentation within the limits of the gas area. For these reasons, therefore, the estimates based on the area-porosity method are regarded as probable rather than proven.
>
> "The areas of probable reserves are Jumping Pound, Princess, Pendant d'Oreille, Manyberries, Black Butte (Pinhorn) Smith Coulee, Leduc, Provost, and Battleview, in Alberta, and Unity in Saskatchewan, as well as a number of small areas in Alberta where the extent of the gas-bearing area is reasonably well known from information primarily supplied by exploration companies".

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(1) Exhibit No. 55 p. 42
(2) Exhibit No. 3 p. 2

From the evidence before it, the Commission concludes that the area-porosity method can provide reasonably accurate estimates of gas in place. In practice, the accuracy of the results obtained depends upon the adequacy and accuracy of the available data on the areal extent and depth of the pay section, porosity and connate water. If the available information on these factors is incomplete or inaccurate the reliability of the method may be greatly reduced, and estimates may either under- or over-state the gas actually in the reservoir.

There are in the Province some areas in which the areal extent of the producing section of the formation has not been determined by drilling, but one or more wells have indicated substantial supplies of gas. Hume includes estimates for these areas within the general category of probable reserves determined by the area-porosity method.

Hume states[1]—

> "In these cases an area of a radius of one mile from each gas well has been arbitrarily selected as the basis for an estimate. If there are two closely spaced wells, as at Battleview, or three as at Elk Point or several as at Lloydminster, each gas area has been considered to be continuous from one well to another, with the outer boundary of the productive area a mile distant from each of the outside wells unless there are reasons for considering it otherwise. In the case of the Vermilion gas field an appraisal made by this method is in reasonable accord with the more precise method based on pressure decline."

It is evident that, in particular fields where the area has not been defined by drilling, the reliability of estimates based upon arbitrary assumptions of area is necessarily reduced, and actual reserves in the field may ultimately prove to be considerably greater than or less than, the amount estimated. Over a number of fields the errors, plus or minus, might be expected to cancel out to some degree.

It will be observed that Hume distinguishes between what he terms "proven reserves", i.e. estimates of reserves in fields for which sufficient production and pressure data are available to justify the use of the production pressure-decline method of estimation; and what he terms "probable reserves", i.e. estimates of reserves in fields for which, because of lack of production experience, the area-porosity method of estimation is used. In both cases the existence of gas in substantial quantity is known. The difference between the two categories of "proven" and probable" as defined by Hume is therefore in the probable error of estimate, plus or minus, in the methods employed. While the error of estimate is probably greater in the applacation of the area-porosity method, it appears to the Commission that the Hume categories of "proven" and "probable" both properly fall within the meaning of the term "existing and proven reserves".

Hume refers to additional areas in which the presence of gas has been established, but in which—

> ". . . . the size of the possible producing fields is not definitely known and cannot be adequately estimated because of the lack of sufficient geological information. Some of these areas have had wells drilled in them but records are so unsatisfactory that no appraisals have been attempted. These are the areas of potential reserves."[2]

The Commission accepts Hume's view that no quantitative estimate of "potential reserves" can be supported. Reserves in this category are beyond the meaning of the term "existing and proven reserves".

In **gas-oil fields** some modification of the methods of estimation, as outlined above, is required. The U. S. Federal Power Commission[3] describes the procedure as follows:

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(1) Exhibit No. 3 p. 3
(2) Exhibit No. 3 p. 3
(3) Exhibit No. 55 p. 43

> "In estimating reserves of solution gas (with oil) two methods are also available —the volumetric and the production-decline. The initial step in the volumetric method for solution gas is the same as for free gas in obtaining the net pore space of the reservoir sands. In addition, however, it is necessary to determine the relative proportions of gas and oil which are in solution together. This rate varies according to the composition of the hydrocarbons and the reservoir pressure and temperature. A determination is made of the number of barrels of oil, at surface conditions of temperature and pressure, which is contained in the reservoir sands. By applying the appropriate gas-oil ratio, the volume of gas in solution is estimated.
>
> "In the production-decline method of determining reserves of solution gas, the future production of oil is estimated down to the point of economic abandonment. To this production estimate for each year there is applied an estimated gas-oil ratio which gives the amount of gas recoverable. This method cannot be used where the production of oil has been limited by "allowables" in accordance with market requirements. Since proration of oil production is widespread, the method has only limited application and is confined principally to certain older fields".[1]

When sufficient information is available, e.g. from the D2 and D3 zones in Leduc, it appears to the Commission that estimates of solution gas may legitimately be included within "existing and proven reserves" **in place.**

In the above it has been assumed that estimates were to be made of the total amount of gas in the reservoir. Estimates of reserves are, in fact, rarely made on this basis. Among the factors which affect the recoverability of gas from a reservoir[2] is the pressure at which the field is likely to be abandoned. This latter element is especially important and it is difficult to predict because abandonment pressure generally involves economic factors which may be influential at some uncertain time in the future.[3]

The Hume estimates are based on an assumed abandonment pressure of 100 pounds per square inch absolute in the reservoir. The validity of the assumption was argued before the Commission. The Commission follows Hume on this point.

The Commission concurs on the viewpoint expressed in the U. S. Federal Power Commission report[4]—

> "Estimating the volume of gas reserves, rather than being an exact science, requires the application of trained judgment to limited fundamental knowledge of underlying conditions. It is evident from even this brief review of methods that the estimation of gas reserves cannot be a precise determination. The results are merely estimates, which are continually subject to change as more complete and accurate information concerning the reservoir is obtained. Estimates may be viewed as spot appraisals of the recoverable supply of gas at a given time. Although estimated figures of reserves are not accurate or precise, they do serve a highly essential function in approximating the magnitude of the recoverable gas. Their periodic redetermination is necessary, moreover, in order that significant trends in the accumulation or depletion of such supplies may be currently indicated as definitely as possible."

III. ESTIMATES OF EXISTING AND PROVEN RESERVES

In the preceding section in this report it was indicated that in the view of the Commission the areas designated "proven" and "probable" by Hume and the other geologists who followed

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(1) Exhibit No. 55 p. 44

(2) For a fuller discussion of recoverability see later section. IV Recoverability & Availability of Gas in Reserve.

(3) Exhibit No. 55 p. 41

(4) Exhibit No. 55 p. 41, 42

his classification, both properly fall within the term "existing and proven" as set out in the reference to the Commission.

The areas herinafter referred to are deemed by the Commission to contain gas in quantities sufficient to be classified as "existing and proven". In the following summary the estimates placed in evidence before the Commission are calculated on the basis of an abandonment pressure of 100 lbs. p.s.i.a. and 60°F., except where otherwise indicated.

The production pressure-decline method has been used as the basis for the estimates in Viking-Kinsella-Fabyan, Medicine Hat-Redcliff, Bow Island, Foremost (Canadian Western) and Turner Valley fields. The volmetric or area-porosity method has been used as the basis for estimates in respect to all other areas. No differentiation is made in this summary as between dry gas, wet gas and solution gas.

Viking-Kinsella-Fabyan Area

This field is located 80 to 90 miles southeast of Edmonton and supplies the system of the Northwestern Utilities Limited and the Town of Wainwright. The principal producing formation is the Viking sand, occurring at a depth of approximately 2,000 to 2,200 feet over an area of approximately 572 square miles. Three detailed estimates of the reserve of gas in this area were submitted, all in substantial agreement. On the basis of the pressure-decline method the estimates are as follows:

Hume	994 billion cubic feet
Pot[1] and Spooner[2]	971 billion cubic feet

As a check, calculations were made on the area-porosity method and the results were as follows:

Hume	1,126 billion cubic feet
Pot	1,153 billion cubic feet

In addition to the foregoing estimates, an estimate of reserves by the material balance method was brought to the attention of the Commission. This estimate was based on a calculation made by Liesemer[3] to an abandonment pressure of 200 p.s.i.a. well-head 60°F. and resulted in a figure of 659.4 billion cubic feet recoverable reserve.

Medicine Hat-Redcliff Area

This area is in and about the City of Medicine Hat and the Town of Redcliff. Production has been taken from wells in this field since 1908. The gas is found in a Colorado shale formation at an average depth of 1,075 feet. Some difference of opinion was expressed by the geologists in respect to this field due mainly to the uncertainty as to the accuracy of basic date used in the pressure-decline method of calculating the reserve. It was necessary to estimate the accumulated withdrawal from the area and also the original Bottom Hole pressure. Spooner made the highest estimate in the amount of 415 billion cubic feet. Liesemer estimated the reserve at 365 billion cubic feet and Hume at 250 billion cubic feet.

Bow Island Area

This area is located about 10 miles north of Burdett station on the Medicine Hat-Lethbridge Canadian Pacific Railway line. The gas horizon is a sand about 35 feet thick in shales of Colorado formation, found at a depth of approximately 2,000 feet. The field was the original source of gas for the Canadian Western System in 1911. By 1927 some 38 billion cubic feet of gas had been withdrawn, the pressure had dropped to 249 p.s.i.a. Re-pressuring tests

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(1) Robert Pot Imperial Oil Ltd. Geological Staff
(2) W. C. Spooner Consulting Geologist, Shreveport, Louisiana.
(3) G. E. Liesemer Petroleum and Natural Gas Conservation Board.

were carried out successfully and from 1930 to 1939, and from 1945 to date Turner Valley surplus gas has been stored in the field during the summer months. A total of approximately 13.75 billion cubic feet has been stored, and the pressure has been raised to over 598 p.s.i. The reserve in this field has been calculated on the pressure-decline method by Hume—25.3 billion cubic feet; Spooner—25.3 billion cubic feet.

Davies[1] estimated the recoverable reserve in this field at about 15 billion cubic feet, basing his estimate on his judgment of the effect of the water drive in the field and the production characteristics of the wells.

Foremost Area (Canadian Western)

This area is located south of Foremost on the Canadian Pacific Lethbridge-Manyberries line. It is presumed, production is obtained from gas sands similar to the Bow Island sands occurring in the lower part of the Colorado shales at about 2,070 to 2,250 feet. The producing area covers approximately 12,800 acres. This field is connected to the Canadian Western pipe line and is used to meet peak load demands on that system. The estimates of reserves in this area on the pressure-decline basis were: Hume—26 billion cubic feet; Spooner—28.4 billion cubic feet. For the same reasons advanced with respect to the Bow Island field Davies estimated the recoverable reserve in this field at 15 billion cubic feet.

Brooks Area

This field is close to the town of Brooks, and has served as a source of gas for the town since 1910. Eight wells of an average depth of 1,300 feet have been drilled in the Milk River formation. In 1946 a well was completed as a gas well in the Sunburst sand at a depth of 3,265 feet. Hume estimated the reserves in this area: Shallow wells, 6.1 billion cubic feet; Sunburst well, 5.2 billion cubic feet—total 11.3 billion cubic feet. Spooner estimated 11.6 billion cubic feet. Weir dealt only with the Sunburst well and estimated the reserve in that well at 5.6 billion cubic feet.

Vermilion Area

The wells in this area are located about 9 miles south-east of the Town of Vermilion. Production is obtained in the sands in the Lower Cretaceous formation, the first at about 1,600 feet, and the second at about 1,900 feet. The sands are of variable continuity and the effectiveness of the sand to produce has been decreased by a silty content. Hume estimated the reserve after allowing for abandoned and reworked wells at 7 billion cubic feet. Spooner's estimate is 10.29 billion cubic feet. It appears doubtful whether Spooner took into account the recent abandoned and reworked wells in the area.

Turner Valley Area

The Turner Valley field is situated about 35 miles south-west of Calgary in the foothills belt of faulted and folded rocks. Production was first taken in 1913 from the Blairmore formation of the Lower Cretaceous age. In 1924 Royalite No. 4 well was completed as a gas-condensate well in the Paleozoic Limestone at a depth of 3,740 feet. The field was developed as a naphtha producing field with accompanying waste of vast volumes of gas, until 1936 when crude oil was discovered on the west flank of the structure. Commencing in 1924 to the present time Turner Valley has been the source of supply of the gas used in the Canadian Western System in southern Alberta. Connell[2] submitted the revised estimate of the Madison Natural Gas Company Limited with respect to the recoverable reserve of this area, residue gas basis, as 270 billion cubic feet, as of January 1st, 1949. This estimate was based on the findings of the Natural Gas Utilities Board. This estimate was adopted by all the other geologists.

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(1) Stanley J. Davies, Consulting Engineer, Calgary
(2) Gordon Connell, Madison Natural Gas Company Limited.

Foremost Area (California Standard)

The reserve in the portion of the Foremost area controlled by California Standard Company was calculated apart from the area controlled by Canadian Western. Production in this area is also found in the Bow Island sand. Hume based his estimate of 17 billion cubic feet on an area of 13,160 acres. Weir[1] calculated a reserve of 25.9 billion cubic feet for an area of approximately 23,200 acres. The area-porosity method was used by both Hume and Weir.

Pendant d'Oreille Area

This area is south-east of the Foremost field and south-west of Pakowki Lake. It is also referred to as the Pakowki area. Production is found in five sands in the Bow Island series at an average depth in the eight producing wells of 2,050 feet. The upper of "A" sand is the main production zone and is found throughout an area of 58,250 acres. The reserves in this sand were estimated by Hume, Beach[2] and Spooner at 224 billion cubic feet. They likewise agreed on the areal extent and reserves in respect to other sand zones as follows:

"B"— 8,000 acres—5.3 billion cubic feet.
"C"— 5,000 acres—6.2 billion cubic feet.
"D"— 2,500 acres—2.6 billion cubic feet.
"E"—10,000 acres—22 billion cubic feet.

Manyberries Area

This area is 35 miles south-east of the Town of Foremost and is down the regional dip from the Pendant d'Oreille field west of Pakowki Lake. It has two producing gas sands in the Bow Island series, with three productive wells. Reserves were estimated by Hume in Manyberries Sand as 24.4 billion cubic feet, and in the Upper sand 6.7 billion cubic feet, a total of 31.1 billion cubic feet, having an area of 8,400 acres. Beach estimated the reserves at 49.5 billion cubic feet over an area of 10,900 acres for the Manyberries sand, and 2,000 acres for the Upper sand. Spooner adopted Beach's estimate of 49.5 billion cubic feet.

Black Butte (Pinhorn) Area

This area is in southern Alberta close to the Montana boundary, about 35-40 miles south-east of Foremost. Pinhorn is about 5 miles west of Black Butte. Three wells have been completed, producing from the Ribbon sand, Ellis sand and the upper part of the Rundle-Mississippi formation. The area taken as a basis of the estimate is 21,070 acres for the Ribbon sands, 2,615 acres for the Ellis sand, and 740 acres for the Rundle sand. Hume estimated the total reserve for the area 39.5 billion cubic feet; Beach 36 billion cubic feet and Spooner 35.9 billion cubic feet.

Smith Coulee

This area is in southern Alberta 27 miles south and 8-10 miles east of Foremost. One well has been completed as a producer in the Bow Island series. Three other wells within a radius of two miles to the north-east, south and south-west have been drilled to test the Bow Island sands above the Lower Cretaceous formation and abandoned. No tests have been made to the north-west and this area is considered prospective. The estimate of reserves in this area by Hume was 2 billion cubic feet for an area of 2,000 acres in the immediate vicinity of the well. Relying on the fact that the three dry holes have previously delineated the field, Beach estimated the reserves at 6 billion cubic feet for an area of 5,000 acres. This estimate was also accepted by Spooner.

Princess Area

This area is situated approximately 150 miles south-east of Calgary and 50 miles north-west of Medicine Hat. The gas and oil zones in this section are as follows: The Bow Island

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(1) Dr. J. D. Weir, Geologist, California Standard Company.
(2) Dr. H. H. Beach—Geologist, McColl-Frontenac Oil Company Limited.

Basal Alberta, (Colorado sand); Basal LowerCretaceous (Sunburst sand); Detrital Zone (Rundle-Madison zone); Devonian (Jefferson) Zone.

The Basal Colorado sand appears to be of a widespread nature in this area. Hume used an area of 19,200 acres in his area-porosity calculation and estimated the reserve in this field to be 93.2 billion cubic feet. Weir agreed that the sand is wide-spread but restricts his estimate to 9,300 acres controlled by the California Standard Company, and estimated the reserves at 48.1 billion cubic feet.

Hume estimated the reserves in the Sunburst sands over an area of 8,350 acres to be 187.1 billion cubic feet. Weir, restricting his estimate to 6,980 acres controlled by the California Standard Company, estimated the reserves at 151.6 billion cubic feet. His estimate for a total area of 8,180 acres is 177.6 billion cubic feet. Hume estimated the reserves in the Jefferson limestone over an area of 7,500 acres to be 81.6 billion cubic feet. Weir, for the same area, estimated 71.3 billion cubic feet. The difference in the above estimates arises from the fact that in his calculations Weir used 30 percent connate water contrasted to Hume's use of 20 percent connate water.

Hume pointed out that though gas was indicated there was no significant production to be obtained in the Bow Island sand, Detrital Zone and the Madison formation in the Princess area. The total estimates for the area were:

Hume	362 billion cubic feet for an area of 37,050 acres
Weir	271 billion cubic feet for an area of 23,780 acres
Spooner	296 billion cubic feet.

Patricia Area

This area adjoins the Princess area on the south and has one completed well in the Sunburst formation. On the basis of an area of 1,920 acres, Hume estimated a reserve of 43.1 billion cubic feet. On the basis of 2,000 acres Weir estimated the reserves at 49.7 billion cubic feet. The difference arises from the fact Weir used a sand thickness of 33 feet for slightly more acres than the sand thickness of 30 feet used by Hume. Spooner's estimate was 49.7 billion cubic feet.

Bantry Area

One well in this area, which is south-east of the Princess area, is dealt with by Weir in his report. For the Sunburst sand covering 640 acres about the well, Weir estimated a reserve of 4.4 billion cubic feet. Spooner used the same figure. Hume did not include this well in his estimate.

Dunmore Area

This field lies 10 to 12 miles south-east of Medicine Hat. Production is obtained from both the Bow Island sand at about a depth of 2,600 feet and the Ellis sand at a depth of 3,306 to 3,325 feet. Hume estimated the reserve in the Bow Island sand at 4.4 billion cubic feet for 1,920 acres, and in the Ellis sand 19.4 billion cubic feet for 5,500 acres,—a total 23.8 billion cubic feet. Weir and Spooner, for similar areas, estimated 6 billion cubic feet and 19 billion cubic feet respectively—a total of 25 billion cubic feet.

Hanna Area

This area is 35 miles north-east of Drumheller on the Canadian National Railway from Calgary to Saskatoon. Production has been obtained both from the Mississippi Limestone and from the Lower Cretaceous Sunburst sand. Hume estimated the reserve in each horizon on the basis of the wells completed, 1,920 acres each, Mississippian 11.8 billion cubic feet; Sunburst 12.7 billion cubic feet—Total 24.5 billion cubic feet. Spooner concurs in this estimate.

Provost Area

The Provost area lies about 160 miles south-east of Edmonton and a few miles west of the Saskatchewan border. Production is from the Viking sand, which has been found in wells over the area. Hume estimated the reserve at 52 billion cubic feet for an area of 25,600 acres, using a 69 percent connate water in his calculations. Pot estimated a reserve of 110 billion cubic feet for an area of 54,400 acres, relying as to the area on sub-surface information available to his company. He also used 69 percent connate water in his calculation. Spooner's estimate was also 110 billion cubic feet.

Elk Point Area

This area is 35 miles north of Vermilion in east central Alberta, north of the North Saskatchewan River. Production is found in the Viking sand at a depth of about 930 to 940 feet, and from the Lower Cretaceous at about 1,252 to 1,262 feet. Hume estimated the reserves—Viking sand, 1,920 acres—2.2 billion cubic feet; Lower Cretaceous, 2,880 acres—5.6 billion cubic feet. Total 7.8 billion cubic feet. Spooner concurred in this estimate.

Jumping Pound Area

The Jumping Pound field is on the eastern edge of the Foothills about 20 miles west of Calgary and 30 miles north of Turner Valley. Four wells have been drilled in this area, three obtained wet gas production and one well established the gas water contact. Production is believed to come from two porous zones in the Palaeozoic (Mississippian) limestone of a combined thickness of about 140 feet, reached at depths from 9,740 to 10,890 feet. Due to the lack of cores the porosity in this area has been established by reference to the similar formations in Turner Valley. Hume, for an area of 6,300 acres and using a porosity factor of 9 percent, estimated the reserve for this area at 920 billion cubic feet. Dodge, a witness called by the Shell Oil Company of Canada Limited, for an area of 5,700 acres, and using a porosity factor of 12 percent, estimated the reserve at 1,053 billion cubic feet. Spooner placed his estimate of 918 billion cubic feet. Brokaw[1] felt the use of a porosity factor of 12 percent was fully justified, and on the basis of 6,300 acres estimated the reserve at 1,201 billion cubic feet. Davies, on the other hand, was not prepared to accept the delineation of the area of the field on the basis of the wells drilled and the information obtained from seismograph work. He felt an estimate of 75 billion cubic feet for the area on the basis of the wells drilled could be a reasonable estimate.

Leduc Field

The Leduc field is a major oil and gas field located about 17 miles south of the City of Edmonton. Gas is encountered in the Viking, Devonian D2, and Devonian D3 zones in this field. The production of gas from the Viking sand is small and varies throughout the area. The gas in the D2 zone is in solution with oil. In the D3 zone there is a gas-cap and also gas is in solution with oil. Pot estimated the recoverable gas from the D2 zone to be 62.4 billion cubic feet; from the D3 zone 514.2 billion cubic feet, including both gas-cap and solution gas. Hume concurred in Pot's estimate. Spooner did not include the D2 zone in his estimate and adopted Pot's estimate of 514.2 for the D3 zone.

Woodbend Area

This area is due north-west of the Leduc field, but as far as is known, is not connected to it. Production of gas from the D3 zone only was taken into account. Pot estimates the recoverable gas for this area as follows: D3 zone—120.6 billion cubic feet. Hume and Spooner concurred in this estimate.

Redwater Area

This area is a major oil field and located about 40 miles north-east of Edmonton. Gas is

(1) Dr. A. D. Brokaw—Northwest Natural Gas Company

in solution with oil in the Devonian D3 zone. Pot estimated the recoverable gas in this area, based on the limited drilling completed, at 129 billion cubic feet. This estimate was adopted by Hume and Spooner.

Athabasca Area

This area lies to the west of the Town of Athabasca 80 miles north of Edmonton. Two wells are producing from the Grand Rapids sandstone formation in this area at a depth of about 1,625 feet. Hume and Spooner, estimated the reserve, for 3,584 acres to be 16.3 bililon cubic feet.

Battleview Area

The Battleview area is located 20 miles north-east of Wainwright and 9 miles south of the Vermilion producing gas wells. It is difficult to correlate the tests for gas in the wells drilled in this area. Hume based his estimate on the records of production of gas from the top of the Lower Cretaceous horizon at about 1,880 to 1,900 feet and pointed out the area of 4 square miles included in his calculation may be very conservative. His estimate was 18.4 billion cubic feet, and accepted by Spooner.

Lloydminster Area

The Lloydminster area is on the Alberta-Saskatchewan boundary in the vicinity of the Canadian National Railway line between Edmonton and North Battleford. The field is an extensive heavy crude oil field. Gas occurs in sandy shales at depths of 1,100 to 1,400 feet and in the sands of the Lower Cretaceous beds. The upper producing horizon of the Lower Cretaceous is the Colony sand with the Sparky and Lloydminster sands occurring about 165 and 280 feet below the top of the Lower Cretaceous respectively. Hume estimated the reserves in this area to be—Colony Sand 14.8 billion cubic feet in the Alberta portion of the field. He did not estimate the Sparky or Lloydminster zones as these zones were primarily oil producing.

Edgerton Area

This area lies 18 miles south-east of Wainwright on the Canadian National main line from Edmonton ton Saskatoon. Hume did not calculate an estimate of this area. Weir estimated, on the basis of the oil well drilled and producing from the Colony sand, a reserve of 6.6 billion cubic feet was established for an area of 2,000 acres. This estimate was concurred in by Spooner.

Pincher Creek Area

The Pincher Creek area in the vicinity of the Town of Pincher Creek on the Crowsnest line of the Canadian Pacific Railway, extends from the railway south to Waterton Lakes National Park. Extensive exploration has been conducted in this area. One well has been completed by the Canadian Gulf Oil Company. This well was drilled to a total depth of 12,516 feet. Reservoir pressure is 4,920 p.s.i.a. A test of the section 11,755 feet to 11,927 feet indicated an open flow capacity of 45 million cubic feet per day. Gas shows were encountered to a depth of 12,200 feet and a test of the entire producing section showed a possible open flow capacity of 60 million cubic feet per day. The average porosity is taken by the company to be 3 percent. Assuming connate water 20 percent, a compressibility factor of .887 and porosity at 3 percent, the company estimated the gas reserve down to 500 p.s.i.a. reservoir pressure to be approximately 75 billion cubic feet for 1 square mile about the well. A further well about 7 miles distant from the first well is now nearing completion. Spooner estimated the reserve for this area in excess of 500 billion cubic feet. He arrived at his estimate by a volumetric calculation showing a reserve of 142,124 Mcf. per acre. His judgment as to the productive area was that it exceeded the section upon which the well was located and would be not less than 3,500 acres. Hume did not make an estimate for this area. He stated on cross-examination—

> "If the second well is as successful as it is hoped, and that hope would be based on general experience in the Foothills area, then the area would probably be larger than what you would assume Mr. Spooner has used; in other words, it will be larger than 3,500 acres if the second well is successful and his estimate of 500 will be conservative. In the absence of data on the second well, it doesn't seem quite reasonable to start making an estimate but I shall be very much disappointed unless the estimate that is eventually proven up in the Pincher Creek area isn't a lot larger than the estimate given by Mr. Spooner. That is simply based on geological interpretations of the possibilities of the Foothills areas. There have been some disappointments."

TABULATED SUMMARY OF RESERVE ESTIMATES
EXISTING AND PROVEN RESERVES

Calculated to 100 p.s.i.a. Abandonment Pressure 60°F.
Billions of cubic feet (MMMcf)

Area	**Hume**	**Spooner**	**Others**	
Viking-Kinsella-Fabyan	994	971	Pot	971
Medicine Hat-Redcliff	250	415	Liesemer	365
Bow Island	25.3	25.3	Davies	15
Foremost (Can. Western)	26	28.4	Davies	15
Brooks	11.3	11.6	Weir	5.6
Vermilion	7	10.3		
Turner Valley	290	290	Connell	270
Foremost (Cal. Std.)	17	(v)	Weir	25.9
Pendant d'Oreille	260	260	Beach	260
Manyberries	31	49.5	Beach	49.5
Black Butte (Pinhorn)	39.5	35.9	Beach	36
Smith Coulee	2	6	Beach	6
Princess	362	296	Weir	271
Patricia	43.1	49.7	Weir	49.7
Bantry	(x)	4.4	Weir	4.4
Dunmore	24	25.1	Weir	25.1
Hanna	24	24.5		
Provost	52	110	Pot	110
Elk Point	7.8	7.8		
Jumping Pound	920	918	Dodge	1,053
			Brokaw	1,201
Leduc	576.4	514.2	Pot	576.4
Woodbend	120.7	120.7	Pot	120.7
Redwater	129	129	Pot	129
Athabasca	16.4	16.3		
Battleview	18.4	18.4		
Lloydminster	14.8	14.8		
Edgerton	(x)	6.6	Weir	6.6
Pincher Creek	(x)	500		
Totals	4,261.7	4,858.5		

(v) Included in Foremost (Can. Western)
(x) Not estimated.

TABULATED SUMMARY OF RESERVE ESTIMATES
EXISTING AND PROVEN RESERVES (HUME)
BY LOCATIONS

Calculated to 100 p.s.i.a. Abandonment Pressure 60°F.
Billions of cubic feet (MMMcf)

Area	Reserve	Total Reserve
Southeastern Alberta		
Medicine Hat-Redcliff	250	250
Bow Island	25.3	
Foremost (Total)	43	
Pendant d'Oreille	260	
Manyberries	31	
Black Butte (Pinhorn)	39.5	
Smith Coulee	2	
Dunmore	24	424.8
Eastern Alberta		
Brooks	11.3	
Princess	362	
Patricia	43.1	
Hanna	24	440.4
Northeastern Alberta		
Viking-Kinsella-Fabyan	994	
Vermilion	7	
Provost	52	
Battleview	18.4	
Lloydminster	14.8	
Elk Point	7.8	1,094
North Central Alberta		
Leduc	576.4	
Woodbend	120.7	
Redwater	129	
Athabasca	16.4	842.5
Foothills - Alberta		
Turner Valley	290	
Jumping Pound	920	1,210
TOTAL		4,261.7

IV. RECOVERABILITY AND AVAILABILITY OF GAS IN RESERVE

In section II, dealing with methods of estimating gas reserves, attention was drawn to the distinction between **gas in place** and **recoverable gas.** It was pointed out that one of the important factors determining recoverability, or the proportion of gas that might ultimately be withdrawn from the reservoir, was the abandonment pressure. The estimates of "proven and probable" reserves have been taken to an abandonment pressure of 100 p.s.i.a.

However other factors than abandonment pressure affect the quantity of gas which will be recovered from a field, e. g.

> "The gas which may be held within the pores of the sand by surface tension, gas pockets trapped off by water encroachment, and various mechanical difficulties in well performance"[1]

S. J. Davies, appearing on behalf of the City of Calgary, dealt at length with the problem of recoverability and availability, and showed the importance of adequate consideration of these factors.

> "It is submitted that the data before the Commission referring to **in situ** natural gas is of theoretical value only and has little practical application to the problem of pipeline gas for the people of Alberta, inasmuch as it affords no evidence of the amount of gas that can be recovered nor the rate at which recovery can be effected, the two principal factors with which we are concerned."[2]

In discussing recoverability, i.e. the quantity of **natural gas** which will ultimately prove available for use or market, Davies directs attention to the proportion of gas in place withdrawn, and to the deductions which must be made to determine the net quantity of usable natural gas.

> "The Commission has had before it data referring to natural gas **in situ,** a 100% sitation. What percentage of this natural gas can be recovered by economic means now available, namely through wells? 80% recovery is a high percentage usually helped by a water drive. 50 to 60% recovery is more usual; with irregular porous horizons recovery is under 50%. . .
>
> "Each natural gas area of the Province must then be examined in detail to determine the amount of natural gas which must be deducted for lifting crude oil, for removal of light hydro carbons, for removal of impurities, and for actual leakage and processing in order that clean pipe line gas may be made available. All of these factors are deductable from the recoverable natural gas which will be produced in the future."[3]

In discussing availability, i.e. the rate at which recovery can be effected, Davies discusses the effect of the rate of withdrawal on ultimate recovery and the use of gas for pressure maintenance.

> "The rate of withdrawal is directly connected to the question of velocity of the gas passing through many pores, irregularly connected to each other. The slower the rate of travel through the limestone the greater the amount eventually recovered. There is therefore for each field and for each well limitations placed upon the withdrawal of natural gas by Conservation Board authority in order that underground wastage does not become too great by blocking off underground porous zones by either water or other liquids, and that by a slow rate of withdrawal the velocity of the natural gas will not become so great as to leave behind in the formation valuable liquids."[4]
>
> "In both cases (Jumping Pound and Pincher Creek) the important point is that it will only be produced over the next 30 or 40 years, and only so much a year is available from the wells now drilled . . . Leduc is another area where gas may be considered as proven but not available for some years in the future".[5]

(1) Exhibit No. 55 p. 41
(2) Exhibit No. 72 p. 5
(3) Exhibit No. 72 p. 2
(4) Exhibit No. 72 p. 3
(5) Exhibit No. 72 p. 2

Finally, Davies states "many of the smaller fields are far from pipe lines or centres of population and can only be of importance to the community in which they are located."[1]

Recoverability

Estimates of gas in place are necessary as a step in determining the quantity of recoverable gas; and therefore cannot be dismissed as of only theoretical value. It is true that less than 100% of the gas in place will be recovered; and that further deduction is necessary, in the case of wet gas, if an estimate of dry clean gas is to be made.

Referring to free gas (as distinct from solution gas) the U. S. Federal Power Commission report[2] states:

> "If an estimate of the recoverable gas is to be made, a recovery factor must be applied to allow for the gas expected to be left in the sands when the field will have reached the limit of economic production. And finally, if the estimate is for dry gas, the recoverable quantity is adjusted as to the condensate and other natural-gas liquids that may be extracted".

Referring to solution gas, the U. S. Federal Power Commission Report[3] states:

> "Since not all the gas is recoverable, inasmuch as some will remain in the void spaces as well as some in solution with the unrecoverable oil left in the reservoir, it is necessary to apply a recovery factor, and also an extraction factor with respect to the liquefiable fractions if the estimate is to be for dry gas alone".

Referring to both types of gas, the U. S. Federal Power Commission report[4] states:

> "The percentage of the gas in place which may be recovered in the case of solution gas is generally less than in a reservoir of free gas. Solution gas recovery may range from below 40 percent to as high as 80 percent of the total gas, whereas the recovery of free gas may be as high as 80 percent or even more".

The extraction factor depends upon the composition of the gas and the liquid fractions that may be extracted. The composition of the gas will likewise determine the deduction to be made for removal of impurities, i. e. mainly sulphur.

All the fields included in the estimates of proven and probable reserves are "dry gas" fields with the exception of Turner Valley, Princess (which are classified as wet gas fields); Jumping Pound (classified as a gas condensate field); and Leduc (in which both gas-cap gas and solution gas occur).

The total estimate for the dry gas fields is 2112 billion cubic feet. A reasonable recovery factor for gas in this type of field would be 90 percent. The recoverable reserves in these fields would therefore total 1901 billion cubic feet. The estimate of 290 billion cubic feet for Turner Valley is "marketable reserve". (Davies' estimate 270 billion cubic feet). The recovery of dry gas from the estimated 362 billion cubic feet for Princess would be in the order of 60 percent, or 217 billion cubic feet. For Jumping Pound (estimated reserve 920 billion cubic feet) Davies suggests a factor of 20 percent to cover "impurities, hydrogen sulphide, carbon dioxide, the light fractions and fuel used to prepare the wet gas as clean pipe line fuel". This would mean a recovery of 736 billion cubic feet of dry gas. The estimated 577 billion cubic feet for Leduc is subject to a recovery factor of 60 percent, which would yield 346 billion cubic feet. The total recoverable and marketable reserve would then amount to 3,490 billion cubic feet.

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(1) Exhibit No. 72 p. 2
(2) Exhibit No. 55 p. 43
(3) Exhibit No. 55 p. 43
(4) Exhibit No. 55 p. 43

Availability

In connection with availability, Davies raised questions both of availability over time and availability in terms of location.

The availability of reserves over time is largely a matter of conservation policy including decisions regarding the number of wells, the rate of withdrawal from individual wells, and the use of gas for pressure maintenance, repressuring and recycling. Within the proven and probable reserves, the problem of availability over time is present in Jumping Pound and Leduc. In Jumping Pound, additional wells would have to be drilled to recover the gas in this field. The provision of a market for gas from Jumping Pound would provide the incentive necessary to proceed with drilling. In Leduc the problem is one of determining whether, and to what extent, gas from the projected extraction plant may be returned to the structure to assist in the recovery of oil. The evidence before the Commission leads to the conclusion that no answer to this problem is yet possible.

Earlier reference has been made to the evidence of W. D. C. MacKenzie, Imperial Oil Limited, on the problems of reservoir-engineering. Dealing particularly with Leduc, MacKenzie[1] states—

> "I have discussed this question with Mr. Pot and at this time he in inclined to recommend that only a portion of the solution gas be returned to the gas-cap in the D3 zone, but he and his staff are in the midst of this study and cannot make any recommendation—this is only a very preliminary opinion".
>
> "Returning part of the gas to the formation and selling the remainder appears to be a logical procedure. In regard to that part that would be returned to the formation it is still problematical as to whether it would increase the ultimate recovery of oil or whether this would be considered only as a gas storage proposition. Our studies must progress further before this question can be resolved."

The evidence of G. W. Govier, Petroleum and Natural Gas Board, confirmed the view that no final decision regarding the disposal of gas from Leduc will be possible until more information is available. Consequently, it might be necessary to contemplate a delay of years—, perhaps 15 or 20 years—before gas from the oil fields would be available in quantity.

With regard to availability in terms of location, Davies suggested that a number of fields were too small and distant from centres of population to be considered as part of the reserve for large transmission lines. The Provost field (also potential fields at Hanna and Stettler) is a relatively large field which illustrates the general problem. Although not too far distant from the larger fields, i.e. the Viking-Kinsella-Fabyan field, the Provost field is to some extent isolated. It might not be necessary to tap the reserves here for the supply of gas to the Edmonton area, for a very long time, particularly in the event gas becomes from the oil fields.

Both questions of availability—in time and in location—are closely related to another matter referred to later in the report, i. e. the construction of a pipe-line grid connecting all the major sources of supply of gas within the province. The advantages of this arrangement in meeting the problems of disposal of residue gas from oil fields, and in protecting particular markets from depletion of local reserves are dealt with later in the report.

V. POTENTIAL NATURAL GAS RESERVES

Known reserves of gas can be estimated with some degree of accuracy, the future of gas discoveries is "inherently speculative."[2]

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(1) W. D. C. MacKenzie Tr. p. 1860

(2) Exhibit No. 55 p. 48

The U. S. Federal Power Commission Report suggests that prospects for the future may be judged from three viewpoints.

"(1) **Past performances regarding additions to known reserves and the industry's record in meeting requirements.**" This approach involves a study of the growth of known reserves, particularly in relation to production and use, i.e. the past trend in the reserve-production ratio. The application of this method was illustrated, in evidence before the Commission, by W. C. Spooner.

"(2) **Analysis of statistical data bearing on the rate of discovery of new gas and the results of drilling operations, including wild cats drilled and number of dry holes.**" This method involves the study of exploratory efforts, as represented by wild cat and development drilling and of the success of these efforts. W. C. Spooner commented on this point, and F. K. Beach, Petroleum and Natural Gas Conservation Board, submitted evidence on drilling operations in the Province.

"(3) **Consideration of the areas believed to be favourable for the finding of oil and gas, and of the extent to which such areas have already been explored".** This areal approach attempts to appraise future possibilities from knowledge of prospective areas of exploration and development. Evidence on this point was obtained from geologists appearing before the Commission, including A. D. Brokaw, T. A. Link, W. C. Spooner and G. S. Hume.

Future Prospects as Indicated by Annual Reserve Estimates and Production

The U. S. Federal Power Commission Report points out,—"If additions to reserves have kept pace with consumption over a substantial period, it is reasonable to expect, in the absence of definite indications to the contrary, that such a trend will not abruptly change".[1] Account must, of course, be taken of any factors tending to accelerate the growth of consumption.

It is not possible to obtain accurate estimates of the known reserves at particular dates in the past. However a reasonable representation of the growth of reserves can be obtained by applying the present estimate of reserves in particular fields or horizons to the year in which the field or horizon was discovered. The record so constructed will tend to advance the expansion of reserves over the past period. Further, in projecting the trend there will be a delayed expansion due to the proving-up of fields not yet fully delineated.

The following tabulation is offered as giving a rough approximation to the reserve position in earlier years:

	Initial Reserves[x]			Production	Net Reserves
	Beginning	Added	End		At end of period
Up to 1926 (1)		3.4	3.4	0.12	3.3
1927-1933 (2)	3.4	0.05	3.5	0.65	2.7
1934-1940 (3)	3.5	0.23	3.8	0.57	2.4
1941-1947 (4)	3.8	2.08	5.9	0.37	4.1

Up to 1926, which included the discovery of Turner Valley, total initial reserves in the known fields were 3.4 trillion cubic feet; total production had amounted to 117 billion cubic feet. Medicine Hat had early been assured of adequate reserves. With the discovery of the Viking

x All figures, reserves and production, are in trillions of cubic feet.

(1) Includes Medicine Hat-Redcliff, 1908; Bow Island 1909; Brooks, 1918; Viking-Kinsella, 1914; Foremost, 1923; Turner Valley, 1924.

(2) Additional fields—Lloydminster, 1933.

(3) Additional fields — Battleview, 1937; Princess, 1939.

(4) Additional fields — all other "Proven" and "Probable".

[1] Exhibit No. 55 p. 48

field Edmonton was assured of supply. Calgary had been seriously inconvenienced by the rapid decline of the Bow Island field; but after 1924, supplies from Turner Valley were available.

After 1926 exploration lagged, and between 1927 and 1933 the only discovery of a new field was at Lloydminster. Total withdrawals in the seven years aggregated 650 billion cubic feet, and were substantially in excess of the addition to reserves. The Battleview and Princess fields were discovered between 1934 and 1940, adding 227 billion cubic feet to reserves; but withdrawals, largely from Turner Valley, totalled 565 billion cubic fet. Thus after the discovery of Turner Valley and up to 1940, discoveries failed to keep pace with withdrawals, and reserves in known fields were reduced by almost 1 trillion cubic feet. It is true that, over the same period, more than 1 trillion cubic feet was wasted; and new reserves were therefore greater than the quantities marketed.

After 1941, stimulated by the search for oil, substantial new discoveries occurred, adding 2.08 trillion cubic feet to reserves, up to the end of 1947. With reduced withdrawals from Turner Valley and the introduction of conservation measures, production for the period totalled only 370 billion cubic feet. Consequently net reserves had increased to 4.1 trillion cubic feet.

	Estimated Reserves	**Production**	**Marketings**	**Ratio Reserves to Production**	**Ratio Reserves to Marketings**
	trillion cf.	MMMcf	MMMcf	(Approx.)	(Approx.)
1927	3.3	20.6	11.9	16	280
1933	2.7	100.8	14.2	27	190
1940	2.4	55.1	15.3	45	160
1947	4.1	49.1	33.4	84	120

Including all Turner Valley gas in the estimate of reserves at 1927, the ratio of reserves to production and marketings was high at that time. By 1933, reserves had been depleted with rapid withdrawal and waste from Turner Valley. In that year reserves represented the equivalent of 27 years production at the current rate[4] and the equivalent of 190 years marketings. By 1940 reserves were further depleted but production was decreasing, due to the decline in Turner Valley. Reserves were equal to 45 years production. Gas marketed had increased only slightly; and reserves represented 160 years at current rates of marketing gas. By 1947, reserves were substantially increased and production (net withdrawals) was less than in 1940. The ratio of reserves to production had increased to 84. On the other hand, gas marketed had more than doubled in comparison with 1940, and the ratio of reserves to gas marketed was approximately 120.

Commenting on the rate at which additions to reserves have occurred in recent years, Spooner states,[1]

> "The drilling activities in Alberta if contined at the current rate or expanded will result in the discovery of substantial oil and gas reserves. In the five-year period ending with 1948, an estimated gas reserve of 2,800,000 MMcf. was discovered."[2]

Projecting the trend of discovery for the five-year period ending with 1948, which would represent a minimum exploration because of increased drilling activities, a reasonable expectation of new gas reserves discovered for a five-year period after 1948 would be 3,000,000 MMcf.

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(1) Exhibit No. 47 p. 35

(2) As indicated earlier in the report Spooner's estimates of proven and probable reserves exceeded those of Hume, principally through the inclusion of 500 MMMcf for Pincher Creek.

In examination, Spooner added,[1]

"As a matter of fact my prediction in there was 3 to 5 trillion depending on the amount of exploration work, but definitely on this trend I feel I can predict a minimum of 3 trillion"; and further—

"Q. Mr. Spooner, am I correct in saying that within the next five years you would add 3 trillion, and then add 3 trillion for the next five years, and then 3 for the next five, which would make a total of, in 15 years, 9 or 10 trillion for that period? Is that as far you would want to go? Is that a fair application of your thoughts?

A. It might be and it might not be. I think it would be a very conservative one."[2]

Future Prospects as Indicated by Exploratory Activity

The prospects of discovery of additional reserves may be judged from both the new reservations taken out in the search for oil or gas, and the actual activity in well drilling.

It was stated in evidence before the Commission[3] that reservations taken out during 1948 exceeded 16,000,000 acres; and that the total area under reservation at the end of 1948 was about double the acreage one year earlier. Within these new reservations geophysical and structural test programs are in progress.

F. K. Beach, Engineer for the Petroleum and Natural Gas Conservation Board, presented evidence on drilling operations.[4]

Number of Wells drilled in Alberta for Oil & Gas

	Completed as			
	Oil Wells	**Gas Wells**	**Dry Wells**	**Total**
To end of 1946	590	274	700	1,564
During 1947	116	33	75	224
To end of 1947	706	307	775	1,788
During 1948	202	20	133	355
To end of 1948	908	327	908	2,143

The number of wells drilled during 1947 and 1948 (579 wells) is 36 percent of the total number of wells drilled up to the end of 1946. The proportion of dry wells up to 1946 was 45 percent. Dry holes during 1947 and 1948 were 36 percent of the total. An increase in drilling activity, and significantly greater success in discovering gas and oil, are apparent in the last two years.

Exploratory wells include the following:

(1) New field wildcats, viz. wells located far from producing pools on a structure that has not produced before:

(2) New pool wildcats, viz. wells located to explore for new pools in a structure already producing:

(3) Shallower pool wildcats, viz. wells located within the outlines of a partly developed pool in search of a reservoir, shallower than the presently producing reservoir:

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(1) W. C. Spooner Tr. p. 1463
(2) W. C. Spooner Tr. p. 1466
(3) A. D. Brokaw Tr. p. 384
(4) F. K. Beach Tr. p. 1619

(4) Deeper pool test, viz. wells located within the production area of a pool already developed (either partly of wholly) but drilled below the deepest known pool, to explore for unknown prospects:

(5) Outpost, viz. wells located with the expectation of extending for a considerable distance the productive area of a developed pool.

Exploratory Wells in 1948

	Successful			Unsuccessful	Total
	Oil	Gas	Condensate		
Outposts	10	5	—	10	25
New Pool Wildcats	2	—	—	6	8
Deeper Pool Wildcats	1	—	—	1	2
New Field Wildcats	0	6	1	99	114
	21	11	1	116	149

The number of new field wildcats drilled during 1948 (114) was substantially greater than the average number of wells drilled per year in the history of exploration in the Province; and represents about one-third of all wells drilled in 1948. This is evidence of very substantial exploratory activity. The proportion of wildcat wells drilled in the United States 1940-46 did not exceed 20 percent in any year.[1]

Further evidence was provided on the number of drilling rigs operating in the Province. The following data was supplied by Beach.

Number of rigs drilling, testing, ready to drill, or incoming on Jan. 4, 1949:

In Leduc	31
In Turner Valley	4
Other areas or fields	47
Total	82

In response to a request for information on the number of wildcat wells which might be drilled by Imperial Oil Limited, W. D. C. MacKenzie[2] stated—That 1949 plans of the Company call for operating ten seismic crews in the field during 1949, and for the drilling of thirty-five wildcat wells.

> "We feel that much greater crude reserves must be found by the industry if Alberta oil is to go outside Western Canada, and to find these reserves it would appear today that the industry has a big job to do in exploration for the next several years."

Future Prospects as Indicated by Extent of Favourable Areas

Additions to known (proven and probable) reserves may be found in deeper horizons in producing fields, in extensions of the present fields, in new areas between or near the presently known fields, and in regions that are not now productive.

Deeper Horizons

The depth of the sedimentary column has been described in the earlier section on "Geology and Natural Gas". Several witnesses appearing before the Commission have testified to the possibility of discovering additional reserves of gas in zones lying below those now producing. It has also been pointed out that, in drilling wells, the upper horizons are not always tested;

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(1) Exhibit No. 55 p. 51
(2) W. D. C. MacKenzie Tr. p. 1862

consequently, additional reserves may be discovered in zones above those now producing. Finally, as a result of improved drilling techniques, gas in commercial quantity may yet be discovered in the location of wells which were abandoned because of no showing of gas or oil. Such explorations are more likely to discover gas than oil.

Extensions of Known Fields

Within the category of "Probable" reserves, Hume has included areas in which one or more wells have made substantial gas. The area of the field has been arbitrarily estimated as having a radius of one mile from each well. In some areas development may prove disappointing; it is equally possible that the ultimate development of these areas will establish additional reserves.

Within the category of "Potential" reserves, Hume has included areas where no adequate estimate of the quantity of gas is possible. The list of these areas, with the substance of Hume's summary comments, follows:—[1]

Dear Horse Coulee—Gas was produced and marketed from one well. Later drilling of these wells obtained no commercial production.

Erickson Coulee—Four wells have been drilled and the prospects do not seem promising.

Del Bonita - Twin River—Twelve wells have been drilled, some of them producing a flow of oil. Commercial gas production does not seem likely.

Suffield—A few shallow wells have been drilled for local use; but the area has no significance as a gas reserve.

Tilley—Eight wells were drilled in the area between 1941 and 1942. Most of these gave discouraging results.

Barnwell (or Chin Coulee)—Some gas was produced from a well in 1917. Subsequent drilling was disappointing. The regional prospects are worthy of further consideration owing to the results of drilling a well in 1945.

Nose Creek—One well drilled. The occurrence of gas and oil in the quantities indicated are not sufficiently important in themselves to warrant drilling for similar results, but they do point to a prospect which, if more favourable porous conditions were found, might have a considerable potential value.

Legal - Morinville—It will be surprising indeed if in the light of our present knowledge of stratigraphy and its relation to oil and gas occurrence, if large gas fields are not ultimately found in this part of the Plains.

Pelican—Early evidence of gas. This is one of the most promising of the undeveloped gas prospects of the Plains area.

Brazeau—Three wells drilled. The question as to whether the Brazeau can be made into a productive oil and gas structure of commercial importance may not be settled until at least one more well is drilled.

Ram River - Clearwater—Seven wells drilled. Although these areas have given small flows of gas at several horizons in the wells drilled, the prospects for developing substantial commercial supplies of gas would seem to be remote.

Keystone Valley—Five wells drilled. Keystone Valley is considered as a prospect for further drilling, which if developed, would greatly enhance Alberta's gas reserves.

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(1) Exhibit No. 3

Moose Mountain—Six wells drilled. The flows of gas were not sufficient to indicate that any substantial quantities could be produced by systematic operations, and the area has not been largely regarded as a commercial gas prospect. However, greater porosity than has so far been found near the centre of the dome would allow for greatly increased yields.

Pekisko—Three wells, some oil. The available information does not give much encouragement for prospecting the higher Palaezoic rocks for a gas supply. It is quite possible, however, that better prospects occur in the Devonian, and at present there are no data on either the stratigraphic position or lateral thickness of possible porous zones.

Eagle Butte—Two wells. It appears that the Eagle Butte area offers further prospects for natural gas developments.

Oyen—The two wells only a mile apart near Cereal do not give much encouragement for any appreciable quantity of gas in this area, even though the first well had a substantial flow of gas.

Wainwright—Although the Wainwright area has not been found to have any appreciable gas reserves, it has been shown to have considerable prospects under local conditions of sedimentation and structure. There is no reason to think that any large volume of gas exists, but small areas may yield substantial flows that could be developed for local use if such were needed. Certain prospects, however, seem largely untested, this further data is not likely to become available until more exploratory wells are drilled.

Delia—There has been widespread evidence of gas in the Delia area. The so-called shallow gas zone with small flows is by far the most continuous horizon but other deeper sands, especially the Viking as reported in Oxville No. 1 well, might have much greater prospects of substantial fields.

Edgerton—The Edgerton area, as far as known from drilling up to the present time, has only the Edgerton Province well as a prospect for gas production.

St. Paul—The area has potential oil and gas prospects.

Areas Between Known Fields

Dr. Brokaw stressed than only a small part of the Alberta Plain had been adequately tested; and referred to a number of substantial areas in which little systematic exploration has been undertaken.

With reference to the Medicine Hat-Foremost-Taber general area, and having in mind the large area between the international boundary and the Oldman River, which has not been so thoroughly tested, Brokaw stated[1] ". . . it is entirely probable that other similar fields exist here, the discovery of which only awaits persistent efforts such as those made by the McColl-Frontenac-Union group in the area about Pakowki Lake".

Referring to the area west of Medicine Hat and lying between Route 3 and Route 1, Brokaw pointed out that testing had been undertaken only to a limited extent, and stated—

> "This area lies on the eastern flank of the Alberta syncline and the search for minor flexures in this type of geological structure has been actively prosecuted in Wyoming and Montana in recent years, and the new Mush Creek field in the Powder River Basin and the Worland field in the Big Horn Basin have been discovered as a result. The area is therefore considered favourable for geophysical exploration".[2]

(1) A. D. Brokaw Tr. p. 363

(2) A. D. Brokaw Tr. p. 373

From Oyen and Hanna areas west to the Foothills belt practically no tests have been drilled; and most of the area south of the Canadian Pacific Railway line from Camrose to Czar has not been tested.

At a number of points during the hearings, comparisons were made between the density of drilling in the Province of Alberta and in other gas producing areas. Up to the end of 1948 the total number of wells drilled in Alberta was 2,143. Mr. A. R. Crozier, Fuel Controller, Province of Ontario, stated that in the relatively small gas-bearing area in Southern Ontario approximately 20,000 wells have been drilled and 3,700 are now operating.[1]

Dr. T. A. Link[2] pointed out that the area of Kansas is only 82,158 square miles, or roughly one-third the area of Alberta, but 75,400 wells have been drilled in Kansas.

Mr. W. S. Campbell called the attention of the Commission to an article by Dr. A. L. Leverson, President of the Geological Society of America, including a map of nine square miles in Oklahoma in which 320 dry holes were drilled, yet 37 oil and gas fields were discovered in the same area.[3]

General Prospects

Link stated,[4] "... the present known proven reserves are the result of an inadequate number of holes drilled, inadequate depths drilled, and have resulted primarily as incidental to drilling for oil"; and hazarded the opinion—"The areal extent of the Sedimentary rocks within the Alberta syncline is of such proportions that if, as and when, the density of drilling becomes comparative to that of oil and gas producing states, the proven reserves will likewise be comparable."

In dealing generally with the potentialities of the Province, Link illustrated several approaches to the problem, viz. the geological evidence of area and depth of sedimentary rocks; the comparison of this potential gas and oil sedimentary fill to other gas and oil regions; calculations based on the estimated cubic miles of sediment in Alberta and the cubic feet per cubic mile of gas in other areas of more intensive development; calculations based on oil explorations and the ratio of gas to oil in the United States. While the Commission considers the quantitative estimates derived by these methods to be no more than interesting speculations, they support the generally expressed view that the potential reserves of the Province are "exceedingly large". (Hume)

The effect of Link's evidence on potentialities in Alberta can be obtained from the following quotations:

> "More than half of Alberta has had essentially no deep drilling done on it, and as Kansas is about one half as large as Alberta, it seems reasonable to assume that in the very near future Alberta should develop twice the reserves of that state—that is, about 28 trillion cubic feet.[5]

Referring to the calculation based on estimated volume of sedimentary rocks in Alberta, times the volume of gas per cubic mile of sediment in areas of intensive exploration in the United States—

> "I must admit that I do not have such calculations prepared, but I feel confident the answer will be in the order of at least 50 trillion cubic feet or more of probable reserves for Alberta. I think that is a very conservative estimate."[6]

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(1) A. R. Crozier Tr. p. 2084
(2) T. A. Link Tr. p. 717
(3) W. S. Campbell Tr. p. 534
(4) T. A. Link Tr. p. 431
(5) T. A. Link Tr. p. 428
(6) T. A. Link Tr. p. 429

> "The State of Texas is known for its size, and it is actually slightly larger than the Province of Alberta. Texas contains the largest gas reserves in the United States, namely 90 trillion cubic feet of proven reserves—not potential. I will not suggest that Alberta will develop reserves of that proportion, but it is not beyond the realm of possibilities."[1]

Using the established ratio of gas to oil reserves in the United States:

> "Informed geologists believe that at least 5 billion barrels of oil will be found in Alberta in the near future. This might mean 35 trillion cubic feet of gas. No large oil pipeline should be contemplated unless 2 to 3 billion barrels of oil are in immediate sight. The corresponding amount of gas on the above ratio would mean 14 to 21 trillion cubic feet of gas, and as a corollary the projected pipeline to Regina thus suggests that amount of gas in sight."[2]

In conclusion:

> "I feel confident that an absolute minimum of 10 trillion cubic feet of gas will be developed in Alberta alone within the next five years."[3]

The following quotations summarize the general views of other geologists:

Dr. Brokaw: "Considering the new reservations, which are roughly equal to the total held on December 15, 1947, and the vast unreserved area in which geological conditions are such as to attract exploration, it is almost certain that the present proven reserves will be increased to many times the present estimates, repeating the experience that has followed development in large potential gas areas.

"Past experience shows that gas is almost always found in oil fields, and in many places, particularly in the Cretaceous beds of Alberta, gas is more widely distributed in occurrence and more frequently found than oil. It is highly probable, therefore, in view of the extensive and widespread exploration under way and to come in the near future that new gas reserves, far in excess of the presently 'proven and probable' reserves as outlined by Hume and others will be revealed."[4]

W. C. Spooner: "The potential gas reserves of Alberta are unquestionably large, but it is not possible to estimate such reserves in terms of cubic feet . . . The slight footage drilled per square mile indicates considerably that the oil and gas development of Alberta represent but a small fraction of the ultimate gas reserve that will be developed over a period of years as markets become available."[5]

G. S. Hume: "We consider the probabilities of finding gas in Alberta, that is, the potential reserves, will exceed those now proven by many times. I do not think that is too optimistic. That is, potential reserves can be many times what we have now proven and probable."[6]

INCENTIVES TO EXPLORATION

Competent witnesses appearing before the Commission generally testified that the Province contained very large reserves as yet not included within the proven and probable reserve estimates. There are likewise general agreement that, providing there was sufficient incentive to proceed with exploration, the estimates of proven and probable reserve would be increased rapidly and substantially.

(1) T. A. Link Tr. p. 428
(2) T. A. Link Tr. p. 430
(3) T. A. Link Tr. p. 432
(4) A. D. Brokaw Tr. pp. 386-7
(5) Exhibit No. 47 p. 35
(6) G. S. Hume Tr. p. 166

With regard to incentives, two points of view were expressed. The dominant viewpoint consistently stated by geologists and representatives of both producing companies and pipeline companies, was that an expanded market for gas, at a sufficient price to the well-owner, was necessary to induce well-drilling activity which would add substantially to the knowledge of gas reserves. The opposing viewpoint, less frequently expressed, was that the main incentive to exploration was the search for oil, and that this could be counted upon, in itself, to bring about substantial additions to the known reserves of gas.

The significance of both factors, i.e. the search for gas and the search for oil, was stated by Hume as follows:[1]

> "The experience of the past where large gas supplies have been found in drilling for oil, will, it is confidently expected, be repeated in the near future. Particularly ought this to be so now that the exploration companies are much more conscious than formerly of the possible early value of gas and will undoubtedly test zones that were at one time disregarded because they gave no evidence of containing oil. If to this presently large projected program of drilling in search of oil should be added the incentive of a price for gas which will justify exploration for this alone with the assurance that a market will be available when sufficient quantities are developed to warrant a market, there would seem to be every expectation that further enormous supplies of gas would be found within a reasonable time."

It was fully admitted that at the present time drilling activity was being undertaken in the search for oil; and significant evidence was presented in support of the contention that, under these conditions, the determination of gas reserves was less complete than it would be if an expanded market for gas were available. Thus, as Hume points out, when wells are drilled for oil alone adequate tests for gas are not usually made; although gas may be present in the formation no estimate of its quantity is obtained. Again, as Beach[2], Petroleum and Natural Gas Conservation Board, brought to the attention of the Commission, wells with substantial gas showing are frequently plugged and abandoned without knowledge of their producing capacity. Such wells, from which the casing is withdrawn, are rendered useless, and the gas in the location could later be produced only by re-drilling from the surface. Finally, in areas established as potential producing areas by reason of the discovery of gas, unless step-out drilling is undertaken, the extent of the field and the quantity of gas in place cannot be estimated. There can be no doubt that exploratory and development activity made only in the search for oil, does not add as rapidly to the known reserves as would occur if the market for oil were supplemented by a market for gas.

It appears to the Commission that the issue is not whether a market for gas would or would not accelerate the acquiring of knowledge regarding the gas reserves of the Province and additions to proven and probable reserves. On the evidence this cannot be disputed. Rather the issue is whether it is necessary or desirable to provide additional stimulus to the search for gas, which a market for gas would undoubtedly provide.

It appears to the Commission that this issue should not be obscured, or confused, by two other arguments advanced during the hearings, viz: that if a market is offered for gas, the well-owners who do not presently have access to existing markets, are entitled to an opportunity to realize on the investment they have made; and, that companies or individuals who have invested substantial amounts in properties capable of producing gas alone, should have an opportunity of obtaining revenue from these properties in order to finance further exploration for oil. These two arguments should be judged on their own merits.

(1) G. S. Hume Tr. p. 120
(2) K. F. Beach Tr. p. 1632

In the judgment of the Commission the first argument raises a problem of equity. The position may be described in this way. At the time exploration was undertaken there was no prospective market for gas. The investment in drilling was made on the chance of finding oil. In the calculation of the risks prior to investment this chance must have been taken into account. In view of these circumstances it appears to the Commission that, while equity to investors might be taken into consideration, the dominant factor is the public advantage from the use of the resource.

The second argument, viz: that a market for gas would provide additional investment funds to be employed in the search for oil, was well represented in the evidence provided by the independent oil producers. The witnesses representing this group of producers, without exception, favoured the opening up of markets for gas in order to provide revenue from an otherwise unproductive asset. It was testified that this additional revenue would be used in further exploration, and on examination it was admitted that the exploration would be in search of oil.[1] It appears to the Commission that, if it could be shown that the independent oil-producing companies were likely to withdraw from the field because of persistent lack of success in the search for oil, this situation might be given serious consideration. However, there is no evidence before the Commission to suggest that the independent producers have been unsuccessful, either absolutely or relatively, in their search for oil. On the contrary, the evidence suggests a substantial degree of success, such as to justify, and to provide funds adequate to promote further exploration.

There is little doubt that an expanded market for gas would provide an additional incentive to the search for oil, both by providing exploration companies with an added source of funds to apply to exploration, and also, through adding to the chance of obtaining revenue, by shifting the risk in favour of further investment. This raises the question of whether it is, at this time, in the public interest to induce a more rapid search for oil.

Attention has already been directed to the intense activity, in progress and contemplated, since the discovery of the Leduc oil field. This activity rests on the considered opinion that substantial reserves of oil are in sight. It appears that, until additional facilities are provided for the transportation of oil, there already exists sufficient impetus to carry forward the search for and discovery of additional oil reserves. Too rapid a rate of discovery could create a serious problem of disposal. Once facilities are available for disposal of oil in large quantities over a wide area, the time may arrive when additional incentive to exploration for oil would be in the public interest. There does not seem to be any substantial case for adding to the incentives at the present time.

In terms of the requirements of the local situation, the Commission cannot avoid the conclusion that the additions to the known reserves of gas, resulting from the present drive for oil, will be sufficient and more than sufficient to maintain a safe relation between proven and probable reserves of gas and withdrawals, on the reasonable expectation that excessive waste will not occur.

If the Commission's analysis of the situation is correct, the argument for an "export" market for gas in order to provide an incentive to the search for gas as such, reduces itself to the statement that an "export" market for gas is necessary in order to provide for the growth of reserves adequate to justify and support an "export" market. This may very well be so; but it remains necessary to show that the "export" of gas is itself in the public interest. This is the real issue.

SUMMARY OF EVIDENCE ON POTENTIAL RESERVES

The Commission does not feel that it can go further than the expert witnesses, most of whom were unwilling to attempt to predict quantities. S. J. Davies, appearing on behalf of

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(1) See Evidence of C. C. Cross and T. L. Brook Tr. Vol. 23

the City of Calgary, took the extreme position when he states that he would not count on any additional reserves until they were proved.[1] On the other hand, Link went so far as to state that an ultimate reserve of 90 trillion cubic feet was "not beyond the realm of possibilities". Other geologists confined themselves to general statements to the effect that potential reserves are "exceedingly large".

Most expert witnesses agreed that substantial additions to reserves could be expected over the next few years. Only Spooner and Link offered quantitative estimates. Spooner estimated 3 trillion cubic feet over the next five years. Link suggested a minimum of 10 trillion cubic feet of developed reserves at the end of five years.

VI. HISTORY OF PRODUCTION AND DISPOSAL OF NATURAL GAS IN ALBERTA

Dependability of data on production and disposal of gas varies with the field. Records from Medicine Hat-Redcliff are in doubt because of early wells that were poorly completed, leaky distribution mains, and unmetered consumption in industries owning their own wells. In this field no records were made prior to 1927. Records are frequently dependent on a transcation between a vendor and a purchaser. The production of gas as a by-product of oil has affected the accuracy of records of gas that did not find a purchaser, but in Turner Valley (the principal place where this has been a problem) even waste gas has been metered since 1933.

It is estimated that up to and including 1948, 1755 billion cubic feet have been withdrawn from all fields in Alberta, and that about one-quarter of this has been marketed. Of the balance more than 1000 billion cubic feet have been wasted, the remainder being used for operations in the field.

Estimates for early years suggest that up to and including 1926, total withdrawal of gas was in the order of 97 billion cubic feet of which some 73 billion cubic feet were marketed.

Between 1927 and 1933 inclusive, total withdrawals aggregated 650 billion cubic feet with 96 billion cubic feet, or roughly 15 percent marketed. The increase in production occurred almost entirely in Turner Valley, where gas was produced as a by-product of oil production. With the decline of the Bow Island field, marketing of Turner Valley gas increased substantially[4] but, over the seven years, gas marketed from the Valley was less than 8.5 percent of withdrawals.

Over the next seven years (1933-40) total withdrawals increased to 565 billion cubic feet, the result of declining production from Turner Valley and the introduction of conservation measures. Gas marketed amounted to less than 19 percent of withdrawals.

Between 1941 and 1947, inclusive, production from Turner Valley continued to decline, and a conservation program involving re-injection of residue gas into the field was put into effect in 1945. However, with increasing demand, total marketings from the Valley were more than 50 percent greater than in the previous seven years; and production and marketings from other fields had almost doubled. Gas marketed accounted for 48 percent of withdrawals over the period.

The position is 1947 and 1948 is summarized below:

	1947		1948	
	Net Withdrawals Mcf.	Marketed Mcf.	Net Withdrawals Mcf.	Marketed Mcf.
Turner Valley	32,342,038	17,285,036	34,611,412	19,019,451
Other Fields	16,659,768	16,068,278	22,936,366	19,331,357
Total	49,001,806	33,353,314	57,547,778	38,350,808

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(1) S. J. Davies Tr. p. 2124

The relative importance of fields other than Turner Valley increased between 1947 and 1948; and for the first time since the Valley became a major producer, gas marketed from other fields exceeded that from the Valley. In both years, gas marketed for utility and industrial use was equal to two-thirds of net withdrawals.

The trends of production and marketing are clearly represented in the accompanying chart.

The disposal of natural gas in 1948 was as follows:

ALBERTA NATURAL GAS, 1948

Quantities in Mcf.

Gross withdrawals	61,034,698
Deduct gas repressured, Turner Valley	3,135,821
Deduct gas repressured, Bow Island	351,099
Net Withdrawals	57,547,778
Marketed	38,350,808
Field Use	6,734,570
Shrinkage	2,714,264
Flared, including meter differences	9,748,136
Total disposals	57,547,778

Note: More gas was taken from Bow Island field in 1948 than was stored. The withdrawals appear as part of the total net withdrawals and the figure above is the quantity supplied from Turner Valley.

Gas used by industries at Medicine Hat-Redcliff is considered as marketed even though used by producers.

Shrinkage is applied only to gas processed. Gas that was not processed would have had some shrinkage if processed, thus reducing apparent amount flared.

Flared includes metering differences of 392,919 of which 391,855 was within the Madison system and was about 1⅓% of handlings; a measure of reliability of metering. Flared gas does not include gas lost through Atlantic No. 3 well in Leduc field which was out of control. That loss may have been of the order of 25,000,000 Mcf.

VII. PRESENT CONSUMPTION OF NATURAL GAS IN ALBERTA

The most complete statement on past and present gas consumption, with estimates of future requirements, was prepared and presented by the major gas distributing companies, viz. Canadian Western Gas Company Limited, and Northwestern Utilities Limited.[1] The historical data included in the submission refer only to sales by the two companies: the summary statement of consumption in the Province, 1948, includes the amount of 5,466,000 Mcf. cubic feet (the actual 1947 consumption) for the remainder of the Province.

GROWTH OF CONSUMPTION (Main Distributing Systems) 1912 - 1948[2]

Total Consumption

Records of the Canadian Western Natural Gas Company go back to 1912, the year in which Calgary was first served with gas from Bow Island. Sales reached a maximum of 4 million Mcf. in 1917, and then fell off steadily to less than 2 million in 1923. During this per-

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(1) Exhibit No. 43

(2) Combined systems of Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited.

iod of decline, occasioned by the rapid depletion of the Bow Island field, consumers in Calgary experience considerable inconvenience. The situation improved following the discovery of the gas-condensate field in Turner Valley in 1924.[1] In this year the line from Viking to Edmonton was completed by Northwestern Utilities, and by 1926 annual consumption on this system was approaching 2 million Mcf.

TOTAL GAS SALES

	Canadian Natural Gas Co. Ltd. Mcf.	Northwestern Utilities Ltd. Mcf.	Total Both Systems Mcf.
1912-1926	42,812,263	4,271,441	47,083,704
1927-1933	50,634,810	18,467,827	69,102,637
1934-1940	57,679,791	22,687,754	80,367,545
1941-1947	107,204,507	51,253,293	158,457,800
1948	19,905,123	12,604,840	32,509,963
	278,236,494	109,285,155	387,521,649

The main features of the growth of gas sales in the systems of the two companies have been,—first, the rapid expansion of sales during the seven-year period 1941-1947 which was maintained through 1948; and, second, the relatively rapid expansion in the system of Northwestern Utilities.

DOMESTIC, COMMERCIAL, INDUSTRIAL CONSUMPTION

Since 1934[2] sales to domestic users have declined in relative importance while the proportion of industrial sales has increased. This change, however, is apparent only in the system of the Canadian Western. The Alberta Nitrogen plant was responsible for the substantial increase in the proportion of industrial sales after 1940. In the Northwestern Utilities system commercial sales have increased at a relatively rapid rate.

Proportion of Domestic, Commercial and Industrial Sales

	Canadian Western Natural Gas Co.			Northwestern Utilities Ltd.			Total Both Systems		
	Dom. %	Com. %	Ind. %	Dom. %	Com. %	Ind. %	Dom. %	Com. %	Ind. %
1934-1940	47	25	28	54	30	16	49	27	24
1941-1947	33	24	43	47	36	17	37	28	35
1948	34	21	45	48	38	14	40	27	33

(1) Imperial Oil Limited became a substantial purchaser of gas at their refinery in Calgary in 1926.

(2) The Basis of Classification of Domestic, Commercial and Industrial users has changed from time to time, but has remained fairly uniform since 1934.

Population, Customers and Sales

The following data were provided by the Companies to indicate recent trends:

Canadian Western Natural Gas Co. Ltd.

Population, Customers and Sales

Domestic:

	Av. No. of Customers	Population	Customers per 100 of population	Sales per customer Mcf.
1936	20,063	107,144	18.7	195
1941	21,590	115,375	18.7	196
1946	26,497	131,037	20.2	221
1947	28,772	134,398	21.4	217
1948	31,199	139,000	22.4	215

Commercial:

	Av. No. of Customers	Population	Customers per 100 of population	Sales per customer Mcf.
1936	3,053	107,144	2.85	657
1941	3,424	115,375	2.97	838
1946	3.562	131,037	2.72	1082
1947	3,841	134,398	2.86	977
1948	4,147	139,000	2.98	980

Industrial: (Excluding Imperial Oil Refinery and Alberta Nitrogen Plant)

	Av. No. of Customers	Population	Customers per 100 of population	Sales per customer Mcf.
1936	122	107,144	0.114	9,836
1941	132	115,375	0.114	12,136
1946	141	131,037	0.108	16,234
1947	148	134,398	0.110	17,397
1948	160	139,000	0.115	18,919

Northwestern Utilities Limited

Population, Customers and Sales

Domestic:

	Av. No. of Customers	Population 97,385	Customers per 100 of population	Sales per customer Mcf.
1941	11,078	130,161	11.4	194.3
1946	17,861	137,161	13.7	232.6
1947	21,178	137,262	15.4	237.1
1948	24,784	146,998	16.9	237.8

Commercial:

	Av. No. of Customers	Population	Customers per 100 of population	Sales per customer Mcf.
1941	1,756	97,385	1.80	839.2
1946	2,307	130,161	1.77	1387.4
1947	2,767	137,262	2.02	1375.4
1948	3,227	146,998	2.20	1426.3

Industrial:

	Av. No. of Customers	Population	Customers per 100 of population	Sales per customer Mcf.
1941	310	97,385	0.318	2413.1
1946	317	130,161	0.244	4490.4
1947	346	137,262	0.252	4197.7
1948	387	146,998	0.263	3984.4

The following points are apparent from a comparison of the record of sales in the two systems, (a) the more rapid growth in number of customers and population in the northern system; (b) the lower saturation of domestic customers (customers per 100 population) in the northern system, where coal has been a more effective competitor; (c) the more rapid increase in saturation of domestic customers in the northern system, so that the saturation is approaching that of the southern system; (d) lower saturation of commercial customers in the northern system, but again a more rapid increase; (e) substantially higher sales per commercial customer in the northern system (f) higher saturation of industrial customers in the northern system, but significantly lower sales per industrial customer.

GAS CONSUMPTION IN MEDICINE HAT-REDCLIFF

Information on the trend of consumption in the Medicine Hat-Redcliff area was submitted by Mr. H. O. Davis, on behalf of the Natural Gas Department, Corporation of the City of Medicine Hat.[1]

Estimated Gas Consumption x: Medicine Hat-Redcliff

	Domestic		Commercial		Industrial		Total
	MMcf	%	MMcf	%	MMcf	%	Mcf.
1937	709	30.5	43	1.8	1,576	67.7	2,328
1941	672	23.5	142	5.3	2,046	71.2	2,860
1946	903	22.1	194	4.8	2,980	73.1	4,077
1947	976	24.3	122#	3.1	2,915	72.6	4,013

x Consumption data include estimates. Complete metering of production was first carried out by the Corporation of Medicine Hat in 1947. In that year the measured production was 16.9% greater than the consumption. It may be assumed that the loss between the wells and the customers has been about 16.9% each year.

# In 1947 some commercial customers qualified as industrial users.

In addition to indicating a substantial increase in consumption, particularly in 1941, the data show the high relative importance of industrial use of gas in Medicine Hat-Redcliff.

SUMMARY STATEMENT OF GAS CONSUMPTION, 1948[2]

SUMMARY—Alberta Gas Consumption in 1948

	Mcf.	Mcf.
Canadian Western		
Domestic	6,699,000	
Commercial	4,066,000	
Industrial	3,027,000	
Imperial Oil Refinery, Alberta Nitrogen and Taber Sugar Factory	5,817,000	
		19,609,000
Northwestern		
Domestic	5,894,000	
Commercial	4,602,000	
Industrial	1,538,000	
Imperial Oil Refinery and City Power Plant	156,000	
		12,190,000

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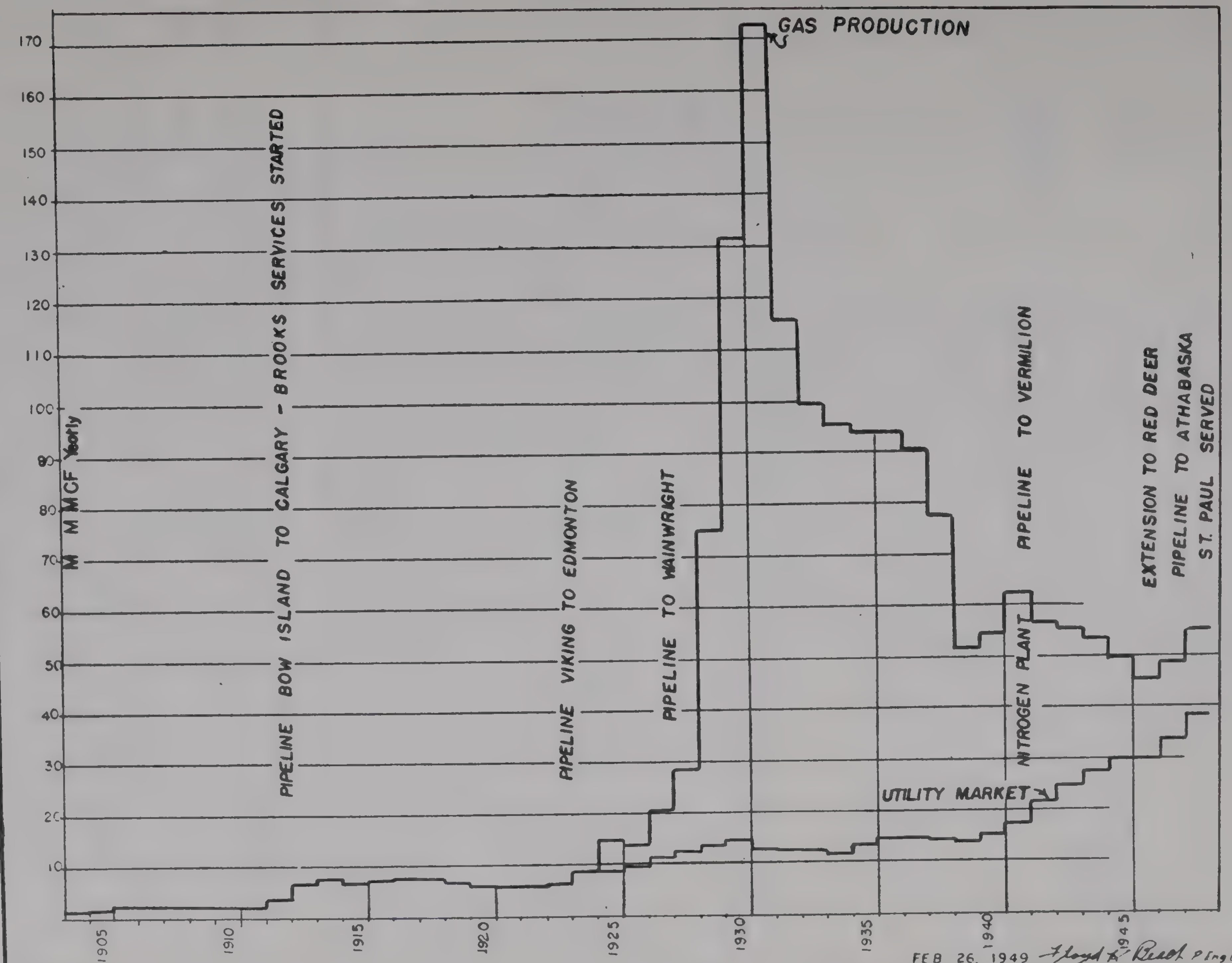
(1) H. O. Davis Tr. p. 54

(2) Taken from the statement by the Gas Companies "Future Gas Requirements of the Province of Alberta." Exhibit No. 43

ALBERTA NATURAL GAS MARKETED

PRODUCTION IS ALSO SHOWN, THE SURPLUS BEING A BY-PRODUCT OF OIL PRODUCTION.



FEB 26, 1949 Floyd K. Beach P.Eng (Alta)

Remainder of Province#	
Presently served communities	5,466,000
	37,265,000

# The amount included is the actual consumption of 1947. As the consumption in that year in the Medicine Hat-Redcliff areas was slightly over 4,000,000 Mcf., consumption in all other communities was less than 1,500,000 Mcf.

VIII. PRICES OF NATURAL GAS

Regulation of Prices

The operation of oil and gas wells in the Province of Alberta is subject to regulation by the Petroleum and Natural Gas Conservation Board, established under the provisions of the Oil and Gas Resources Conservation Act. The chief function of the Board is to fix the "allowables" for each producing oil and gas well in the Province on the basis of sound conservation practices. The duties of the Conservation Board do not extend to the regulation of prices.

The sale of natural gas at the wellhead, and the gathering, processing and transmission of gas in each oil and gas field, are regulated by the Natural Gas Utilities Board, established under the provisions of the Natural Gas Utilities Act. The Board consists of the Chairman of the Petroleum and Natural Gas Conservation Board and the Chairman of the Board of Public Utility Commissioners.

Supervision of the service rendered by gas utility companies, and of the rates charged to consumers, is the function of the Board of Public Utility Commissioners, established under the Public Utilities Act.

Several features of the Natural Gas Utilities Act deserve special mention. The Act provides that any contract purporting to give the exclusive right to sell or supply, purchase or take delivery of natural gas in the Province shall be null and void, to the extent such contract and/or arrangement restricts or reserves in any manner the right to sell or supply or purchase or take delivery of natural gas. The Act further provides that no future contracts shall contain any exclusive right of the kind referred to above. It was under the above provisions of the Act that the contract between the Canadian Western Company and the Royalite Oil Company, providing for the exclusive right in Royalite to supply the gas required by the Canadian Western system to the extent it was able so to do, was abrogated and is no longer in effect as an exclusive contract. The Act further provides that every proprietor of a pipeline is to be a common carrier and every proprietor of every pipeline engaged in gathering and transmitting gas shall be a common purchaser with respect to any field to which the service extends, subject to the Board order and subject to the allowables fixed from time to time by the Petroleum and Natural Gas Conservation Board.

Several features of the Public Utility Act also are worthy of note. The Act contains a provision that the powers of the Board as to public utilities shall not apply to any public utilities owned or operated by any municipal corporation unless and until the same is brought under the Act by by-law approved by an Order of the Lieutenant Governor in Council. The act also provides that in considering and acting upon any application or matter before the Board involving the question of rates charged for service by any public utility, the Board shall not make any order or direction to raise the rates for any such service beyond what the proprietor of the public utility may desire to impose.

In the Province of Alberta at the present time three distinct conditions occur.

1. The consumers collectively own the gas field and gas wells and distribution systems, e.g. Medicine Hat. In this situation the Board of Public Utility Commissioners does not have authority to regulate the price to the consumer; and, since there is no sale of gas in the field, the Natural Gas Utility Board is not in a position to exercise its authority.

2. The distributing company selling gas to the consumer also holds the gas field and wells on long term leases, e.g. Northwestern Utilities in the Viking field. In this case since the full cost of drilling, operating and maintaining the wells, and of the transmission of the gas from the field to the municipalities is dealt with as a unit the Board of Public Utility Commissioners has set the regulated price to the consumer on the overall cost of the entire operation of the company.

3. The distributing company owns a part of the transmission system from the field where the gas is produced (Canadian Western Natural Gas Company), and another part of the system is owned by another company (Madison Natural Gas Company Limited), and the wells in the field are owned or held under lease by a number of individuals or companies, e.g. Turner Valley. The Board of Public Utility Commissioners has jurisdiction to establish the rates for the services rendered by the distributing company in transmitting the gas from the field to the municipality and distributing the gas within the confines of the municipality; and to fix the price charged to the consumer. The Natural Gas Utility Board has jurisdiction over and fixes the rates to be charged by the Company or companies providing the gathering and compression service in the field and in addition thereto the well head price to be paid to the owners of the wells from which the gas is produced.

The rates fixed by the Board of Public Utility Commissioners and the Natural Gas Utilities Board with respect to services rendered in gathering, compressing, transmitting, and distributing gas, are determined in accordance with universally recognized principles of public utility regulation.

It is generally conceded that the fixing of the well head price for gas is not a matter to which the principles of public utility regulation apply. The Natural Gas Utilities Board has to date had occasion to fix the price of gas at the well-head in only one instance, namely, Turner Valley. In summing up the Board stated:

> "The Board is not directed to fix a well head price which will result in the public paying for gas an amount equivalent to the competitive price of coal, with some arbittrary allowance for intangible factors, nor is it directed to fix a price to the commercial consumer which will induce him to continue the uses of gas instead of converting to coal. The price fixed must necessarily be a judgment figure related to the cost of the service now given and the initial costs which have been incurred for the dual purpose of making a waste product available to the market and conserving gas for the future, and these must all be weighed against the various factors just discussed, and if possible some equilibrium maintained between the past and future demand."

The Board also stated:

> "Having given consideration to the regulatory principles previously discussed and having applied these principles to the entire record on this phase, and having considered the volume of production, the need for compression, scrubbing, repressuring and the nature and extent of the field, well spacing and the like, the Board is of the opinion and so directs that 3c per Mcf. is a just and reasonable basic well-head price to be paid to the producers for gas going to the residue markets, discounted in the case of all repressured gas on the basis previously discussed."

On the initial application the price fixed was 3 cents per Mcf. at the well-head. In September 1948 the Board increased the price from 3 cents to 4¾ cents per Mcf. at the well-head in Turner Valley.

In its reasons for the Order increasing the price above mentioned the Board dealt with a number of arguments advanced before it. In particular, dealing with an objection by the Calgary Property Owners Association to the increase in price based upon the removal of sales tax or upon the comparative price of coal the Board stated:

> "They stress the former waste nature of this product and the fact that gas supply is greater than the demand; that the continued prosperity of Calgary depends upon natural gas being available at the lowest possible price. The statute, however, enjoins the Board to fix prices which are just and reasonable, and, while a just price to the producer may have some effect on consumers, that effect must not result in an unreasonable consumer price. Rising costs are no doubt disagreeable and unfortunate, but to single out the gas industry as the only one which must carry on at former rates in the face of its ever-rising costs is to deny to that industry the relief which this Statute affords to them. If the Board must give consideration to the consumer at the expense of the producer, it will be denying the objects for which this legislation was passed."

It is apparent that machinery is available to regulate the prices to be charged for natural gas in the Province. It would be reasonable to expect that, just as the increase in discoveries of gas has had no effect on prices in the past, an increase in demand would have little effect on prices in the future, provided such prices are determined on principles consistently applied by the regulatory boards of the Province.

RETAIL PRICES OF GAS

The retail rates for gas charged by the city of Medicine Hat and the companies distributing gas in the Province are set out in Appendix I to this report.

GOVERNMENT REVENUES DERIVED FROM PRODUCTION AND DISTRIBUTION OF GAS.

The revenue derived by the people of Alberta from the production and distribution of gas is obtained through three sources. First, royalties reserved by the Crown with respect to the production of gas from the areas leased by the Crown; second, taxes levied on gas in place in freehold lands; and third, by levy on the assessed value of pipe lines.

The current form of petroleum and natural gas lease issued by the Crown provides that the maximum royalty payable on the petroleum during the first term of the lease shall not exceed one sixth or 16 2/3 per cent of the gross recovery from the lands therein described. The Order-in-Council presently in effect provides that the royalty computed, levied and collected on natural gas obtained from provincial lands, including school lands, and consumed for some useful purposes or sold, is fifteen per cent of the selling price or fair value at the time and place of production; provided that in no event shall the royalty be less than three-quarters of one cent per thousand cubic feet (Mcf).

The officials of the Department of Lands and Mines reported to the Commission that during the period April 1st, 1948, to November 30th, 1948, royalty in the amount of $64,000 was collected on natural gas and it is estimated by the Department officials that collections for the fiscal year ending March 31st, 1949, will approximate $110,000.00.

The taxes levied on the production and distribution of gas, other than gas produced from Crown lands, are levied under the provisions of two different Acts, namely: The Mineral Taxation Act, 1947, Chapter 10 of the Statutes of Alberta, 1947; and The Pipe Line Taxation Act, Chapter 52, Revised Statutes of Alberta 1942.

Section 4 of The Mineral Taxation Act, 1947, provides that on or before the 31st day of December in each year, every owner shall pay a tax on the mineral or minerals within, upon or under the tract of which he is the owner at such rate per acre, not exceeding five cents per acre, as may from time to time be determined by the Lieutenant Governor in Council.

Section 7 of the Act provides that the Minister may by order published in The Alberta Gazette designate any area in the Province as a producing area and designate the mineral or minerals which, for the purposes of this Act, shall be deemed to be the principal mineral or minerals in the area. Every owner of a principal mineral in a producing area shall be liable to be assessed and to pay a tax levied on the principal mineral under the provision of the Act, which tax shall be in addition to and not in substition for the tax imposed in Section 4.

The officials of the Department of Lands and Mines advise that the basis for the mineral tax levied in respect to the producing areas in which natural gas has been designated as the principal mineral is as follows:—In every year an assessment is made of all producing gas wells. The method of assessment is set forth in the schedule of the Act, Section II;

> "The fair actual value for the purpose of assessment in any year for the natural gas within, upon or under the land allocated by the Minister to a well producing either natural gas alone or both petroleum and natural gas shall be four times the value at three cents per thousand cubic feet of the natural gas produced from the well during the preceding year".

The rate of tax for the year 1948 on the assessed value of producing gas wells was established by Order-in-Council at eight mills. The acreage tax for the years 1948 and 1949 was established by Order-in-Council at one and one-half cents per acre.

The officials of the Department of Lands and Mines advise that revenue from the taxation of all minerals from the first of April, 1948, to December 31st, 1948, was: on the acreage tax basis $119,699.91; from producing area tax, $278,935.80; a total of $398,635.71. The foregoing includes the tax on petroleum, natural gas and coal. The portion thereof attributable only to natural gas is estimated by the Department to be $33,350.00.

Pipe lines, including the producing strings in wells when connected with the pipe lines, are assessable under the Pipe Lines Taxation Act. The taxes, however, on such assessments are held in abeyance at the present time under the Provisions of the Dominion-Provincial Taxation Agreement, so far as rural municipalities are concerned. Towns and villages, however, still assess and tax pipe lines and distribution lines within their borders, not under the Pipe Line Taxation Act, but as improvements upon the land and subject to the general mill rate of the municipality.

The assessed value for the pipe lines in the Canadian Western Natural Gas Company for the year 1941, the last year of assessment, was $1,714,000.00; for the Northwestern Utilities Company, $1,187,800.00; the total assessed value of all pipe lines in the Province was $6,473,680.00. It should be noted that this assessment includes casing in the oil and gas wells. The rate levied on the pipe lines, including the casing in the wells was at the rate of 10 mills on the dollar. The taxes paid in the year 1941 were as follows: Canadian Western Natural Gas Company, $17,140.00; Northwestern Utilities Company, $11,878.00; total for the Province which includes casing in both oil and gas wells, $64,736.00.

Reference is made to the taxation by the towns and villages of the pipe lines within the borders thereof. The Commission is advised that in most instances the pipe lines pass outside the towns and villages and the revenue to the towns and villages from this source is very small.

It will be observed that the Crown royalty is 15 per cent of the value at the well head of the gas produced, or a minimum of three-quarters cent per Mcf. Three-quarters of one cent is equal to 15 percent of five cents. By establishing three-quarters of one cent as the minimum royalty the Crown indicates that, for the purpose of collection of royalty, natural gas is valued at five cents per Mcf. In Turner Valley where the well head price of gas has been fixed by the Natural Gas Utilities Board at four and three-quarter cents per Mcf. the Crown collects three-quarters of one cent royalty on each Mcf. produced from Crown lands. In the Viking-Kinsella field where the Northwestern Utilties Company owns the gas in place by virtue of the fact that it is lessee from the Crown, the royalty payable on Crown lands is also three-quarters of one cent per Mcf. notwithstanding the fact that there is no actual sale and purchase of the gas.

Except for the area lying between Calgary and Medicine Hat, in the vicinity of the Canadian Pacific Railway right-of-way, the mineral rights of the Crown and the mineral rights of freehold interests, the railways and other other individuals, are owned, for the most part, in alternate sections. It therefore follows that in most gas producing areas throughout the Province the gas sold will be produced from both Crown and freehold sections and the revenues accruing from the sale of gas will accrue to the Crown partly by way of royalty and partly by way of mineral tax.

As a comparison of the revenue derived by way of royalty and by way of tax the following illustration is submitted—In the case of two wells in the same gas field, one situated on a Crown lease and one situated on an adjoining freehold lease and producing the same volume of gas per year, namely 100,000 Mcf., the royalty payable to the Crown by the holder of the Crown lease would be 100,000 x ¾c or $750.00. The mineral tax payable by the holder of the freehold lease will be 100,000 x 3c x 8 mills or $96.00. It should be pointed out that the freehold leaseholder in addition to paying mineral tax will be paying an over-riding royalty to his landlord, the holder of the minerals in fee, of approximately 12½ per cent. On the basis of a valuation of gas at five cents per Mcf. the freehold lessor would receive by way of royalty 100,000 x 5c x 12½% or $625.00.

COMPARATIVE COSTS OF NATURAL GAS AND COMPETING SOURCES OF ENERGY

In discussing inter fuel competition the Report of the United States' Federal Power Commission points out[1] that four major elements affect the relationships between natural gas and other fuels. These elements are, first, the Btu. content of a unit of the fuel; second, the relative efficiencies of use, and other advantages and conveniences; third, quality, particularly reliability of supply; and fourth, price.

> "The price range within which there will be effective inter fuel competition is a resultant of the various factors noted. Depending on their circumstances and requirements, some users may be interested chiefly in heat and energy content. Their measure of competitive price will be reckoned closely in accordance with the cost of an equivalent amount of energy from another available fuel. Other purchasers, however, may be attracted primarily by certain qualities more readily or completely obtainable from one fuel, such as greater cleanliness, convenience, uniformity of operation, or ease with which it may be used. Consideration of such factors will then weigh heavily in their choices, within broad limits as to price differences. In other instances it may be the ability or willingness of one supplier to deliver his fuel at all times and without limitations, or to provide some other attribute of good service. As regards all of these matters, the selection of the individual residential customer, as distinguished from the industrial users of fuel, will also depend upon his standard of living and his willingness and ability to pay.
>
> In selling natural gas or any other fuel to many customers, wide differences are

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(1) Exhibit No. 55 p. 255

encountered in the importance attached to these various elements."[1]

The competing fuels which may be considered in Alberta are fuel oils, electricity, and coal. Fuel oils and electricity may be dealt with briefly; coal will be discussed more fully.

FUEL OILS

At the request of the Commission, J. F. Langston, P. Eng. reported on the comparative costs of fuel oils and natural gas in Calgary, as follows:[2]

> **Domestic:** "Fuel oil, as marketed in Calgary for domestic consumption, has in the past been supplied by the Oil Companies from Diesel fuel stock, since the specifications of these fuels are quite similar, and individual storage for domestic use is unwarranted where such a small volume is marketed.
>
> The Imperial Oil Limited give the following quotation on their Esso Diesel Fuel Oil Medium and Star Fuel Oil; 12.5c/Imperial Gallon, fob refinery, with delivery charges at 1c/gallon, making a delivered price of 13.5c/gallon.
>
> The specifications of this fuel are as follows:

A.P.I. Gravity Average	37.4°
Lbs. per Imperial Gallon	8.4
Gross Btu Content	19,100 Btu/lb.

> Assuming 70% efficiency in domestic installations for this fuel, and assuming the same efficiency for natural gas, it is seen that fuel oil at 13.5c/gallon is equivalent to natural gas at 84c/Mcf." (The domestic price of gas in Calgary is 28.2 cents per Mcf.)
>
> **Commercial and Industrial:** "The Imperial Oil Limited quote a price for Esso Bunker Fuel Oil of 5.75c/gallon f.o.b. Calgary Refinery, and a tank wagon price of 6.75c/gallon.
>
> The following specifications are accepted for this fuel oil:

A.P.I. Gravity	14°
Lbs. per Imperial Gallon	9.69
Gross Btu/lb.	18,500
Gross Btu/Imperial Gallon	180,000

> An efficiency of 75% is assumed for the use of this fuel oil and at the same natural gas is assumed to have an efficiency of 75%.
>
> It is seen then, that one Mcf of natural gas with 1,000,000 Btu's, is equivalent to 5.55 Imperial Gallons of Esso Bunker Fuel with 180,000 Btu's/Imperial Gallon. Then, with Esso Bunker Fuel at 6.75c/Imperial Gallon delivered, the equivalent price of natural gas would be 37.5c/Mcf."
>
> (The industrial price of gas in Calgary is 12.6c per Mcf.)

From this evidence it is clear that, at present prices, natural gas is considerably cheaper than fuel oil.

ELECTRICITY[3]

Domestic: "The Combination domestic rate as existing in Calgary is one of the low-

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(1) Exhibit No. 55 p. 296

(2) Exhibit No. 134

(3) Exhibit No. 134

est in the four western provinces. The rate as advertised by the City of Calgary is as follows:

Combination Light and Heat (Private residences only)

For the first 25 K.W. Hrs.	5c/K.W. Hr.
For the next 150 K.W. Hrs.	1.75c/K.W. Hr.
All over	1.1c/K.W. Hr.

A discount of 15% is allowed for prompt payment.

Minimum bill—$1.77.

Users who are not on the Combination Rate buy electricity at 5c/K.W. Hr. with a minimum bill of 85c.

The following tabe shows the net bill for various monthly quantities, and shows the equivalent price per Mcf. of gas.

K.W. Hrs. per Month	Net Bill	Avge. Cost per K.W. Hr.	Equiv. Price Mcf. Gas Gas Eff. - 70% Elec. Eff. - 90%
15	.72	4.8 c	8.87
20	.85	4.25	7.85
40	1.50	3.75	6.93
60	1.58	2.63	4.85
80	1.88	2.35	4.34
100	2.18	2.18	4.03
300	4.46	1.49	2.75
500	6.33	1.27	2.35

Commercial and Industrial: "It is not suggested here that electricity should be considered competitive with natural gas for Industrial Heating.

In order to complete the comparison however, the lowest price per K.W. Hr. obtainable from the City of Calgary is 0.82c/K.W. Hr.

Even considering electricity to have an efficiency of 95% and natural gas to have an efficiency of 75% in industrial applications it is seen that one Mcf of gas would be equivalent to 232 K.W. Hrs. with the price per K.W. Hr. of 0.82c. The equivalent price of natural gas would be $1.90/Mcf."

It is evident that, at present prices, natural gas is considerably cheaper than electricity.

COAL

If the heat value of natural gas is taken to be 1000 Btu per cubic foot, comparisons between coal and natural gas on a heat unit basis can be readily made, given the Btu content of the coal.

The Research Council of Alberta[1] gives the following heat values for Alberta coals:

	Coal	Btu./lb.
Group 1	Low volatile, non-coking bituminous coals from mountain areas. (Cascade, Nordegg, Mountain Park-Luscar)	14,000
Group 2	High volatile, coking, bituminous coals from mountain areas. (Crowsnest, Mountain Park-Cadomin and Mountain Park)	13,200

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(1) E. Stansfield & W. A. Lang "Coals of Alberta" Report No. 35, 1944, p. 51

	Coal	**Btu/lb.**
Group 3	Sub-bituminous coals, principally from foothills areas. (Coalspur, Lethbridge, Prairie Creek, Saunders)	10,900
Group 4	Domestic coals — fair storage from prairie areas. (Carbon, Drumheller, Edmonton, Pembina and Taber)	9,700
Group 5	Domestic coals — poor storage from prairie areas. (Camrose, Castor, Sheerness, Tofield)	8,300

Thus if Lethbridge coal has a Btu content of 10,900 per pound, on a heat unit basis the competitive price of Lethbridge coal per pound is 10.9 times the price of natural gas per cubic foot.

Comparisons of coal and natural gas on a heat unit basis do not take account of the utilization efficiency of the two fuels.

> "A fuel can be not better in the results of its use than the equipment in which it is burned. Technical efficiencies of equipment and appliances vary considerably, and some of the fuel industries have advanced more rapidly than others in certain respects in the development of improved and efficient equipment. Hence not only is there competition between the fuels as such, but there are also important differences in and competition between the facilities which utilize the fuels"[1]

J. F. Langston[2] suggests the following efficiencies, with the comment that efficiencies "are somewhat indefinite as to manner of determination, especially in the smaller installations, but are considered to err to the advantage of coal".

Use	**Coal**	**Gas**
Domestic	55%	70%
Commercial and Small Industrial	65%	75%
Industrial	65%	75%

Thus, taking account of the relative efficiencies of natural gas and coal, as well as the heat unit content, the competitive price for Lethbridge coal per pound is 8.6 times the price of natural gas per cubic foot, **in domestic uses**; and 9.4 times the price of natural gas per cubic foot, **in commercial and industrial uses.**

> "The other advantages of gas over coal, of cleanliness, availability, continuity of supply, lack of necessity of storing supplies or investing in reserve supply, lack of fire hazard, lower equipment repair and maintenance costs, elimination of labour and handling equipment, are well known and will not be further emphasized in this submission. Coal and gas are compared on a straight B.T.U. basis with adjustments made on a relative efficiency basis. Additional savings by the use of gas are definite in value but are not taken into consideration."[3]

The current rates for natural gas on the system of Northwestern Utilities Limited, and competitive prices for the groups of coal referred to above, are shown in the following table:

		Competitive Coal Prices/Ton				
	Natural Gas	Group 1	Group 2	Group 3	Group 4	Group 5
Use	c/Mcf	$	$	$	$	$
Domestic	27.2	5.98	5.66	4.68	4.13	3.54
Commercial	20.5	4.96	4.67	3.85	3.44	2.95
Industrial	16.4	3.97	3.74	3.08	2.75	2.36

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(1) Exhibit No. 55 p. 348
(2) Exhibit No. 119 p. 2
(3) Exhibit No. 119 p. 3

Langston[1] discusses the comparative costs of coal and gas to consumers in Calgary, as at January, 1948.

> "Drumheller coal is mainly used in Calgary. Some Blairmore coal is used in a few installations. As compared to 1945, the price of Drumheller coal has advanced from $8.30 per ton to $10.25 per ton for domestic use; for commercial use (stoker coal) it has advanced from $6.00 per ton to $7.25 per ton; for industrial use, stoker coal has advanced from $4.00 per ton to $5.25 to $6.00 per ton, depending on trackage and unloading costs of car load lots. Priddis coal has advanced from $6.00 per ton to $6.80 or $8.00 per ton depending on consumer's contract. Blairmore coal has advanced from $7.50 per ton to $8.75 per ton.
>
> The B.T.U. values of the coals used in this submission are:

Drumheller	9,850 B.T.U. per pound
Priddis	12,750 B.T.U. per pound
Blairmore	12,840 B.T.U. per pound

Domestic Use

Taking Rate No. 2, Canadian Western Company, viz. First 4 Mcf $1.50 per month; all additional Mcf $0.25 per month, Langston states:

> "On an equivalent basis and under the relative efficiencies of 55% for coal and 70% for gas, Drumheller coal at $10.25/ton is equivalent to 66c per Mcf; Blairmore coal at $8.75/ton is equivalent to 43.3c per Mcf; and Priddis coal at $8.00/ton is equivalent to 39.8c per Mcf.
>
> These figures show that on this basis alone coal for domestic use is not competitive with gas."

Commercial and Small Industrial Use

Taking Rate No. 5, Canadian Western Company, viz. Fixed Charge $1.00 per month, plus 26c per Mcf for all gas used, Langston states:

> "On an equivalent basis using an efficiency for coal of 65% and of 75% for gas, Drumheller coal at $7.25/ton (stoker coal) is equivalent to 42.5c/Mcf; Blairmore coal at $8.75/ton (mine run) is equivalent to 39.4c/Mcf; and Priddis coal at $8.00 per ton is equivalent to 36.3c/Mcf, or at $6.80 per ton is equivalent to 30.8c/Mcf.
> Here again, as in the case of domestic use and with no allowance for the many other advantages of natural gas, its present price is well below competitive values on a straight heating value basis. This is emphasized by experience as when the price of gas in Calgary was 33c per Mcf, approximately 87% of all commercial customers served used gas for heating purposes."

Industrial Use

Langston uses Rate No. 4,[2] Canadian Western Company as representative of the price of natural gas and for convenience sets out the following average rates per Mcf:

Average Monthly Use	Average Rate per Mcf.
600 Mcf.	26.0 cents
1,000 "	24.0 "
2,000 "	21.0 "
3,000 "	19.0 "

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(1) Exhibit No. 119 p. 3

(2) Canadian Western Company has a lower rate (Optional High Load Factor Rate) for large individual users with a steady demand.

Average Monthly Use	Average Rate per Mcf.
4,000 "	18.0 "
5,000 "	17.4 "

Langston states:

> "On a straight comparison of B.T.U. values, i.e. considering efficiencies for the two fuels to be the same as might occur in really modern coal power plants, the Drumheller coal at $5.25 per ton would be equivalent to 26.7c/Mcf; and the Priddis coal at $6.80 per ton would be equivalent to 26.8c/Mcf."

It seems unnecessary to comment at any length on the above evidence, all of which points to the fact that, at prevailing prices of coal and natural gas, natural gas is a relatively cheap fuel; and there is a strong incentive to shift from the use of coal to the use of natural gas. Such a price relationship between competing fuels cannot be considered normal; and its continuance could hardly fail to bring about a reduction in the use of coal and an increase in the use of gas.

If gas prices, under Public Utility control, remain at close to their present levels, either coal prices must decline or coal consumption be drastically reduced. However, the Commission is not in a position to predict future prices. The future relationship between coal and natural gas prices is uncertain. At the same time there is reason to believe that natural gas will remain a relatively cheap fuel, and that its price will continue to provide an incentive to increased use.

IX. INDUSTRIAL USES OF NATURAL GAS

The Commission in assessing the importance of natural gas as a factor in location of industry has considered primary industries utilizing natural gas as a raw material, secondary industries utilizing the products of primary industries for further processing and other industries using natural gas for heat and power. Cognizance has been taken of the fact that the evidence presented to the Commission is somewhat divergent and there has not been time for those presenting submissions to assemble adequate supporting data. An effort has been made to include in this report only those factors which seem to be pertinent to Alberta.

The importance of natural gas to industry was given in a number of submissions. The following table showing the consumption pattern of natural gas in the United States taken from the submission of H. Zinder,[1] illustrates the large proportion of natural gas that is used by industry in the United States. The location of the industrial development is also indicated.

Consumption of Natural Gas in the United States by Principal Uses, 1945 and 1946.

	Quantities (Billions of cubic feet)		Percent	
Kind of Use	**1945**	**1946**	**1945**	**1946**
Industrial				
Oil and Gas-field Operations	917	898	23.5	22.4
Carbon Black Production	432	478	11.1	11.9
Petroleum refining	338	332	8.7	8.3
Electric Public Utilities	326	307	8.3	7.6
Cement Plants	38	58	1.0	1.4
Other Industries	1,012	1,038	25.9	25.9
Total Industrial	3,063	3,111	78.5	77.5
Domestic	607	661	15.6	16.5
Commercial	230	242	5.9	6.0
Total U. S. Consumption	3,900	4,014	100.0	100.0

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(1) Exhibit No. 58 p. 33

> Regionally, the consumption of natural gas is concentrated largely within the six principal gas-producing states of Texas, Louisiana, California, Oklahoma, West Virginia and Kansas, which among them accounted for more than two-thirds of the total consumption."

Another statement taken from "Economic Factors Which Control Gas Field Development" prepared by the Petroleum Statistics Bureau Inc.[1] also emphasizes the importance of natural gas in the development of industry.

> "an application has also been filed with the Federal Power Commission and with the Provincial Government of Alberta, Canada, to construct a natural gas pipeline from the prolific gas fields of Alberta Province, running westward to Vancouver, British Columbia, via Seattle, Washington, with a branch line extending southward to Portland, Oregon.
>
> "This transmission line would enable the Pacific Northwest region to obtain urgently needed natural gas fuel, **for the conversion of its abundant raw materials into manufactured products** and to service with natural gas its fast growing population.
>
> "The Pacific Northwest region is particuarly in need of natural gas. The price of manufactured gas is abnormally high, coal and oil is scarce and high priced, and the potential development of that great region is being held back by the excessive cost of fuels."

Alberta, a young province with a limited population, is as yet not industrialized to any extent. However, as pointed out in the Research Council of Alberta Submission,[2] Alberta is a rich agricultural province with large potential reserves of energy in the form of coal, oil, natural gas, bituminous sand and hydro power. In addition large areas of forests occur in the Western and Northern part of the Province, and deposits of limestone, shale, clay, sand, salt, etc., occur in other sections of the province. The combination of raw materials for industry, large reserves of material for producing heat and power, and a rich agriculture to support growth in population, makes Alberta occupy a unique position in the economy of Canada. The policy to be adopted in the development of these resources is therefore of prime concern not only to Alberta but to Canada as a whole.

The pattern of the industrial utilization of natural gas as a raw material in the chemical and synthetic industries has changed materially in recent years. This fact is borne out by the following excerpt taken from the report of Commissioner Nelson Lee Smith, and Commissioner Harrington Wimberly, Natural Gas Investigation, Federal Power Commission.[3]

> "The development of products and production process starting with natural gas has been very slow. This condition has been due principally to the high order of chemical technology required in any synthetics manufacture, and secondly, to the difficulty of performing the reactions with the relatively inactive hydrocarbons making up dry natural gas. The entire industry of organic synthetics is, in fact, scarcely 20 years old. During the last decade, and more especially in the last 5 years, the research laboratories of the chemical companies found in dry natural gas as well as in the natural-gas liquids desirable properties and qualities for their use as chemical raw materials. It was only during World War II, however, that national importance became attached to the possibilities of large-scale commercial production using the laboratory discoveries which made these developments possible.

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(1) Exhibit No. 30 p. 31
(2) Exhibit No. 67 p. 2
(3) Exhibit No. 55 p. 416

> "While the rapid acceleration within the past 5 years was due initially to the needs for increased production occasioned by the war, it has, nevertheless, given rise to a large and rapidly growing permanent industry. Under the pressure of war necessity, the chemical research laboratories, working in parallel with the petroleum refining technologists, developed methods of reacting these compounds and found ways to obtain the necessary hydrocarbon supplies from natural gas as well as petroleum.
>
> Their commercial exploitation has already expanded from the orthodox chemical field of small volume production chemicals into the mass production of common products for wide distribution. The "natural-gas liquids" have for some time been employed on such a scale as to provide an important segment of the constituents in premium-grade liquid fuels, particularly for aviation. As a result of these developments the way has been opened, with respect to the lighter as well as the heavier components, for a large production of basic organic chemicals considered impossible even a few years ago.
>
> "Since the commercial production of any synthetic product requires a combination of feed materials and chemical processes carefully designed to fit the special needs of the product, the development of synthetic methods using natural gas is a continuous procession moving along with the development of the products themselves. In some instances existing processes, based on other raw materials, are being adapted to use natural gas for additional supplies of already recognized products. Here natural gas as the new feed stock must, along with its synthetic process, meet the competition of the other feed stocks and their processes. In other instances the availability at low cost of large quantities of natural gas has made it posible to produce synthetic products in larger quantities or at lower costs. Some of the newer synthetic production plants employ natural gas to produce entirely new types of synthetic products. Some of them just reached commercial-scale production being converted to meet the special needs appearing in World War II. Plans for both new processes and products discovered during the war are being turned to peacetime applications. The organizations undertaking this job require a high order of technical skill and management. They must combine comprehensive research in the problems of both production and utilization to provide superior products. All of the processes, as well as the products themselves, are the result of persistent laboratory research. In many instances the laboratory products are entirely new synthetic compounds, not only commercially unknown but also without natural counterparts with which their suitability may be compared. Such laboratory research is going forward steadily, and even at an accelerating rate, to discover other new processes and products and to test them for present and new uses."

The advantages of natural gas as an industrial fuel were pointed out in the Submission of the Research Council of Alberta.[1]

> "Natural gas is one of the highest grade fuels for industrial use. Its high calorific value, which is about twice that of most of the higher calorific value gases made from coal, together with the relatively small amounts of excess air required for its complete combustion, means that high calorific intensities and flame temperatures can readily be obtained by burning natural gas in suitable equipment. The ease with which combustion can be controlled and the cleanliness of operation gives it marked advantages over solid fuels. The temperatures and atmospheres required in industrial processes can be closely and easily regulated. Many of the problems encountered in the utilization of other fuels are entirely absent in the case of natural gas. It

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(1) Exhibit No. 67 p. 32

> is essential, of course, that a continuous supply should be available at a price competitive with other fuels."

Evidence presented to the Commission has recommended that in considering the future of the natural gas reserves of the Province due consideration should be given to the use of natural gas for power purposes. Once the capital expenditure for gas mains is made to take gas to or by any location the gas can be efficiently converted into electrical or mechanical power by either large or small producing units.

Methods of converting natural gas to power and of its costs per KWHr. as fuel, were included in the Research Council of Alberta Submission.[1] One significant statement was that gas turbines of 2,000 KW to 5,000 KW (max) capacity require no cooling water other than a small quantity for the lubricating oil system. Such equipment could be installed anywhere in the province irrespective of there being relatively large quantities of water such as are required for steam plants or large gas engines. When large quantities of cooling water are available the steam turbine with its boilers is more efficient than a gas turbine. Steam units up to 60,000 KW outlet are available with optimum efficiency. The use of large steam units with utilization of waste heat for central heating or for use in an industrial plant have attractive possibilities.

Shortages of hydropower in the Provinces of Ontario and British Columbia during the winter of 1948-49 have clearly demonstrated the importance of developing alternative sources of power in Alberta. Because of its resources of hydro power, coal, oil and natural gas, Alberta could, by designed development, assure industry of an uninterrupted supply of power and this would be a major attraction to industries with high capitalization and high operating costs.

Natural gas is of major importance to the synthetic organic chemical industry because of the versatility of hydrocarbon conversion processes, and of the wide variety of chemicals which can be made from the constituents of natural gas. In the production of many other products, not classed as synthetics, increasing quantities of synthetic organic chemicals are used as intermediates in their manufacturing processes. The production of synthetic ammonia, nitrates and fertilizers, not ordinarily grouped with organic chemicals, has experienced a marked expansion using natural gas as the fuel stock, and this shows indications of sustained growth. Markets for many of the chemical products are limited but for others they are large.

J. R. Donald[2] referring to the future of the Synthetic chemical industry in Alberta, stated:

> "Looking at the larger field of the markets of Canada, further afield, the petrochemical industry offers a good many possibilities. In the United States southwest, chemicals, such as acetone, acetic acid, aldehyde, butanol, methanol, synthetic rubber, nylon resin, glycerine and other base materials required in Eastern Canada can in some instances be produced in Alberta and shipped to Eastern Canadian markets. Another range of products which would seem to offer attraction are the chlorinated hydrocarbons such as carbon tetrachloride, trichlor ethylene, chloroform, etc. Some of these products are made in Eastern Canada from acetylene. It is very possible that with natural gas here, manufacturers could compete in the eastern markets. As an example of this type of industry, the ammonia plant here in Calgary is a good example. Fertilizers produced from the ammonia here can compete successfully in the Eastern Canadian market with similar products manufactured from solid fuel. As a matter of fact, the ammonia plant at Calgary is in a position to turn out various other valuable chemical materials, such as methanol, hexamine, urea, and these materials are base materials for an important range of plastics. **Quite apart from the**

(1) Exhibit No. 67 p. 7
(2) J. R. Donald Tr. p. 2169

> United States markets to the south, I think it is quite evident that in the larger Canadiam market and in other export markets that Alberta industry will be built up and find export outlets".

Later this same witness when discussing the industrial needs of Canada in case of another national emergency, stated:

> "With the general power shortage as it exists in Eastern Canada and with the general fuel shortage as it existed during the war, Alberta would provide a very attractive picture for industrial expansion. . .".
>
> "During the last war, in Canada we were largely dependent on the United States for toluol and the toluol was largely obtained from the petroleum industry. Alberta is the only point in Canada where new and additional large supplies of toluol might be available: and combined with tolual you have the nitric acid and other acid supplies necessary for large scale explosive production. A somewhat similar situation exists in connection with high octane aviation fuels."

Considerable concern has been expressed in recent years regarding future supplies of liquid fuels.

Dr. W. C. Schroeder, Chief, Office of Synthetic Fuels, Bureau of Mines, Washington, stated recently:

> "Whenever fuel requirements are discussed in long-range terms, the subject of synthetic liquid fuels is brought to the foreground. With few exceptions, oil company executives agree that coal, oil shale and natural gas are destined to become a major source of oil supply. The major issue is 'when'."

The present status of synthetic liquid fuels in America including cost data are given in the Research Council of Alberta Submission.[1] With respect to the possibility of synthetic plants in Alberta it was stated that:

> "It now seems unlikely, with present successes in oil exploration, that synthetic plants will be required in Alberta for many years to come, unless as a national emergency. It is considered possible, however, in view of the marked advances in synthetic fuel techniques in recent years and with the huge sums of money that are being spent on research and development in this field, that new processes or modification of present processes will be achieved which will result in the costs of synthetic gasoline and other oils equalling or even costing less than gasoline from crude petroleum."

Schroeder is authority for the statement that a synthetic fuel plant utilizing natural gas and producing 10,000 barrels per day of primary products would require 120 million cubic feet of gas per day, 43 billion cubic feet per year, approximately 1 trillion cubic feet over the life of the plant, which because of its high capital cost would require to be amortised over a period of approximately 25 years.

The production of carbon black from natural gas is essentially a chemical process, and one for which large amounts of gas are consumed annually in the United States. Canada in 1946 imported over 41 million pounds of carbon black valued at nearly 3 million dollars. The carbon black was used largely in the production of synthetic rubber at the Polymers Corporation plant at Sarnia, Ontario.

Carbon black is produced in areas of the United States having cheap natural gas. The Channel process is very wasteful of gas and is only possible where gas is being wasted. Yields of carbon black by the newer furnace and thermal decomposition processes are much higher

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(1) Exhibit No. 67 p. 24, 25

than in the Channel process so that a higher priced gas might be used and the product compete with that produced by the Channel process from low cost gas. Carbon blacks made by the various processes have slightly different physical characteristics.

H. Zinder,[1] in his submission and also on the stand, presented evidence on the importance of fuel in the location of industry and of the shifts in industry due to natural gas. Many of his statements were based on a study made in 1939 by the Natural Resources Committee entitled "Industrial Location and Natural Resources". In his studies of recent trends he had to rely largely on scattered statistical data or qualitative information since there is as yet a serious lack of statistical quantitative material which can be used to analyze shifts that have occurred since 1939. Furthermore, he stated that such shifts as have occurred are to a large extent an admixture of wartime and postwar construction. He urged that caution be exercised in stating any unqualified conclusions on this subject pertaining to the postwar industrial shifts which may have been caused by the availability of natural gas resources.

In the 1939 study it was concluded that the availability of cheap or abundant natural gas was not generally effective in motivating the migration of industries in the United States.

In his study, based on 1939 conditions, Zinder stated:[2]

> ".1) The most important economic factors determining location of industry, in decreasing order of significance are:
>
> (a) Market considerations
>
> (b) Labour — cost differentials
>
> (c) Raw materials, including fuel considerations
>
> "(2) The availability of cheap or abundant natural gas is not, generally, of itself an effective determinant in the location of industries, even among the most intensive gas users. Since this is true for these industries, it must be even more so for manufacturing industries in general, in which, during recent years, fuel has contributed 1.5 percent to the total value of the product (exclusive of costs of transportation to the market and of distribution)."

Zinder said,—

> "On the basis of the available facts which have been developed in recent studies, it appears that this earlier conclusion is still basically valid, although it must be qualified because of the deficiency in the available quantitative statistics relating to postwar industrial shifts. It is known, for instance, that the Houston, Texas, area is currently experiencing one of the largest construction booms in the United States. It is more difficult to assign the precise cause or to ascertain how much of this represents migration from other regions and how much reflects general nationwide expansion."

Donald stated in his evidence that as a result of the stimulation of war, something like a billion dollars was invested in the chemical industry in the Southwest (United States) and since the end of the war a further $500 million has been committed to investments there.

This evidence coupled with the findings of Commissioners Nelson Lee Smith and Harrington Wimberly in their report of the Natural Gas Investigation of the U. S. Federal Power Commission,[3] that the development of products and production processes starting with natural gas has been very slow, but that as a result of wartime developments the way has been opened

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(1) Exhibit No. 58 Tr. p. 1543
(2) Exhibit No. 58 p. 3
(3) Exhibit No. 55 p. 416

with respect to the lighter as well as the heavier components of natural gas, for a production of basic organic chemicals considered impossible even a few years ago, cast some doubt on the applicability of the earlier findings of the National Resources Committee to present conditions. Indeed, it may emphasize the growing importance of natural gas in industry.

In the 1939[1] survey it was found that only six percent of all manufacturing industries, accounting for less than ten percent of the total value of products, had fuel costs representing more than four percent of the value of that product. Industries, in which fuel was an important factor, were blast furnace products, cement, brick and tile, clay products, hardwood distillation, lime, roofing tile and sewer tile.

Natural gas for fuel in petroleum refining is a recent significant development. Evidence presented at the Natural Gas Investigation of the U. S. Federal Power Commission showed that during World War II the use of natural gas as a refinery fuel increased 240 percent from 148 billion in 1941 to 355 billion in 1946, indicating that natural gas provided most of the increased wartime fuel requirements of petroleum refineries.

The importance of the use of gas for fuel in these industries is significant to Alberta, since as stated earlier, Alberta has deposits of limestone, shale, clay, sand, salt, etc. Furthermore, the rapid growth of the petroleum industry in Alberta will necessitate a material increase in the refinery capacity for processing oil.

The amount of natural gas consumed by manufacturing industries of Alberta, compiled from data supplied by the Dominion Bureau of Statistics are shown in figures No. 8 and 9 of the Research Council of Alberta Submission.[2] The greatest amount was used for processing non-metallic products including brick, pottery and glassware. Testimony submitted to the Commission disclosed that nine industrial organizations, with total annual payrolls in excess of two and one-half million dollars, located in the vicinity of Redcliff and Medicine Hat solely due to cheap natural gas being available in large volume.

Donald in giving evidence before the Commission relative to Alberta's industries, stated:[3]

> "In the first place we have industries such as the cement industry and ceramic industries which, using mineral raw materials available, find great advantage in the use of cheap fuel in the convenient form as represented by natural gas. It seems evident that the cement industry in Alberta, for example, will expand and will supply the prairie market. The same thing applies to brick, tile, gypsum and other products."

The present production of cement in Alberta is approximately 4,000 barrels a day. This industry presently uses coal for burning the clinker but if converted to natural gas would require about 2 billion cubic feet a year. Alberta also has a lime industry in which gas could be used. Nearly 36 thousand tons of lime, valued at $235,000, were produced in 1947.

Reviewing other industrial developments in Alberta, Donald said:[4]

> "Another type of industry which is bound to expand in Alberta are industries in the chemical field supplying the local demands here. The large established salt deposits here in Alberta are a source of salt chemicals. At present these chemicals are imported from Eastern Canada. I think there is no doubt that in the relatively near future, with the future demands arising from these products and the high cost of transportation from the East, that you will see a salt industry established producing such products as caustic soda, chlorine, hydrochloric acid and soda ash. With these

(1) J. R. Donald Tr. p. 2172-3
(2) Exhibit No. 67 Figures 8, 9
(3) J. R. Donald Tr. p. 2,175
(4) J. R. Donald Tr. p. 2,177

basic chemicals available at a reasonable price, numerous other industries become possible".

The plant, for the recovery of salt, recently built at Lindberg, Alberta, develops its heat from natural gas obtained from gas wells at the plant site.

The rapid development of oil production in Alberta during the last two years and the increased need for oil refining capacity offers another large outlet for natural gas.

Industries processing animal and vegetable products from Alberta farms used in 1946 approximately two billion cubic feet of natural gas. As agricultural developments in the province expand and as more of the farms are converted to mixed farming, the use of gas in this industry should increase.

Plans are under consideration for the establishment of one or two large pulp and paper mills in Alberta for which available supplies of natural gas are a consideration since large amounts of heat are required in the process.

Evidence was given that sulphur, either as sulphuric acid or elemental sulphur, could be recovered from sour natural gas in certain gas fields in Alberta. The present market for sulphur is limited but as the chemical industry develops the market for sulphuric acid will increase.

While discussing possible future developments in Alberta, Donald stated:[1]

> "I would like to say to you that this question of the United States chemical industry considering establishments in Alberta is not just a matter of fancy. A number of the larger chemical companies have been studying this Alberta situation. My own organization has had a request from one of the larger users of petro-chemicals to advise them in general on this situation and they talk in very substantial quantities of natural gas and propane and butane. I don't think there is any doubt that such developments will take place. However, I think it is important to recognize that in the first place such developments require exceedingly large amounts of capital. For example, the ammonia plant here cost something like ten million dollars in 1940-41; of course, today the investment would be considerably larger. Now investments of that type can only be made where there is an assured source of raw material supply over a considerable period and consequently establishment of this type of chemical industry requires very adequate reserves of natural gas."

In discussing the possible extent of future developments, Donald said:[2]

> "As a result of the stimulation of war, something like a billion dollars was invested in the chemical industry in the Southwest (United States) and since the end of the war a further $500 million has been committed to investments there.
>
> "These developments were undertaken, some of them were undertaken primarily in the war effort, but they have been absorbed in the ordinary industry of the United States, and investments have been made by the largest and most important bodies in the American Chemical Industry.
>
> "In other words, since 1938 the United States with a population of 150 millions, or something in that order, these are just round figures, has invested about one and one-half billion in chemical industries in the Southwest, and, in addition, of course there have been further capital outlays in allied industries.
>
> "Now if we assume a Canadian population of 15 million—or about a tenth that of the United States—a similar development in Canada, in Alberta, similar to what has taken place in the Southwest will involve a capital expenditure here of 150 million."

(1) J. R. Donald Tr. p. 2,180
(2) J. R. Donald Tr. p. 2-173-4

X. FUTURE REQUIREMENTS OF NATURAL GAS IN ALBERTA

Estimates of the Gas Distributing Companies

Reference was made in the earlier section on "Gas Consumption" to the evidence submitted by the two major gas distributing companies. Their submission,[1] described the growth of consumption, summarized the consumption in 1948, and included an estimate of gas consumption at 1960.

The procedure adopted in estimating consumption at 1960 was: (a) to provide for increases in consumption in the cities and towns now served by the companies; (b) to estimate additional consumption in towns not presently served; and (c) to add a further quantity for additional possible industrial enterprises.

For the centres of consumption now served the companies' estimates of consumption at 1960 (and actual consumption in 1948) are summarized below:

SUMMARY—ALBERTA GAS CONSUMPTION IN 1948 AND ESTIMATED REQUIREMENTS IN 1960

Canadian Western:	1948 Mcf	1960 Mcf
Domestic	6,699,000	8,400,000
Commercial	4,066,000	4,500,000
Industrial	3,027,000	3,600,000
Imperial Oil Refinery, Alberta Nitrogen, and Taber Sugar Factory	5,817,000	6,180,000
Sub-total	19,609,000	22,680,000
Additional Possibilities		2,420,000
TOTAL—Canadian Western	19,609,000	25,100,000
Northwestern:	1948 Mcf	1960 Mcf
Domestic	5,894,000	11,400,000
Commercial	4,602,000	7,600,000
Industrial	1,538,000	2,200,000
Imperial Oil Refinery, and City Power Plant	156,000	3,780,000
Sub-total	12,190,000	24,980,000
Additional Possibilities		4,780,000
TOTAL—Northwestern	12,190,000	29,760,000
TOTAL (now served by the Companies)	31,799,000	54,860,000

The estimated increase of 23,061,000 Mcf over the 12-year period, 1948-1960, represents an average annual increase of just less than 2,000,000 Mcf.

Statistically, increased consumption in centres of population now served will reflect the influence of the following factors: (i) population growth; (ii) saturation of customers per 100 population; and (iii) sales per customer.

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(1) Exhibit No. 43 Future Gas Requirements of the Province of Alberta.

The basis of the estimate for Canadian Western is set out below:

Canadian Western Natural Gas Co. Ltd.	**Population, Customers & Sales**	
	1948	1960 (est.)
Domestic:		
Average No. of Customers	31,199	39,800
Population	139,000	173,000
Customers/100 pop.	22.4	23.0
Sales/Customers (Mcf)	215	210
Commercial:		
Average No. of Customers	4,147	5,000
Population	139,000	173,000
Customers/100 pop.	2.98	2.90
Sales/Customers (Mcf)	980	900
Industrial (Ex. Refinery and Nitrogen Plant)		
Average No. of Customers	160	190
Population	139,000	173,000
Customers/100 pop.	1.115	0.110
Sales/Customers (Mcf)	18,919	19,000

As sales and saturation are both held close to, or are less than, 1948, (a conservative position in view of past trends), the principal factor responsible for the estimated increase in consumption is the estimated increase in population and number of customers. The Company's submission treats separately of population trends in Calgary, Lethbridge, and the other towns now connected to the system. The population of Calgary is estimated to increase some 25,000 over the 12 years, or at the rate of rather more than 2,000 per year. Lethbridge population is estimated to increase 6,000 over the 12 years, i.e. at the rate of 500 per year. Other towns are estimated to increase 250 a year, on the average, over 12 years, i.e. by a total of 3,000. The total increase of 34,000 would raise the population from 139,000 to 173,000 by 1960.

The basis of the estimates for the Northwestern Utilities is as follows:

Northwestern Utilities Limited	**Population, Customers and Sales**	
	1948	1960 (est.)
Domestic:		
Average No. of Customers	24,784	49,500
Population	146,998	225,000
Customers/100 pop.	16.9	22.0
Sales/Customers (Mcf)	237.8	230
Commercial:		
Average No. of Customers	3,227	5,600
Population	146,998	225,000
Customers/100 pop.	2.20	2.5
Sales/Customers (Mcf)	1426.3	1360.0
Industrial:		
Average No. of Customers	387	560
Population	146,998	225,000
Customers/100 pop.	0.263	0.25
Sales/Customers (Mcf)	3984.4	3930.0

Sales and saturation are both held close to, or less than, 1948, in the commercial and industrial classification. The saturation of domestic customers is raised from 16.9 to 22.0 per 100 population. This increase brings the saturation on the Northwestern system to approximately what it now is on the Canadian Western system, and is based on the assumption that the present trend away from coal and to gas, for domestic use, will continue. Apart from this, the main factor contributing to the increase in the estimate is the projected increase in population and number of customers. The Company's submission treats separately of population trends in Edmonton and in other towns now connected to the system. The population of Edmonton is estimated to increase some 75,000 over the 12 years, or at the rate of 6,250 per year. The population of other towns is estimated to increase more slowly. The total increase estimated is from 146,998 to 225,000.

In addition to the increases based upon analysis of population trends, the companies increase the consumption of the Imperial Oil Refinery, Alberta Nitrogen and Taber Sugar Refinery (Canadian Western) by 363,000 Mcf; the Imperial Oil Refinery and Edmonton City Power Plant (Northwestern) by 3,624,000 Mcf. Allowance is also made for additional possibilities, on the two systems, of 7,200,000 Mcf. It is understood that this figure is in part based upon new services which the companies have under consideration at this time.

The City of Edmonton, in a brief presented by Commissioner Menzies[1] refers to the estimates of the Gas Company and states: "The Company also anticipates that the growth of this city will be gradual. Our view, however, is that the estimate of the Company with regard to increased population and gas consumption in Edmonton is conservative. Moreover, we believe that the growth of this city in population and in the development of its commercial and industrial activities will not be gradual, but for some years will show a constantly accelerated increase and we suggest that the statement quoted from the City records and the documents hereto attached tend to support this view'. Reference has already been made to the comments in the City's brief on the inclusion in the Gas Company's estimates of the use of natural gas as fuel for the boilers in the Edmonton Power Plant.

In the estimates for 1960, the gas companies also anticipate serving other centres of population not now connected to their systems. These points include Fort Saskatchewan, Oliver and Namao; towns between Calgary and Edmonton; towns between Calgary and Lethbridge; and Banff-Exshaw, including the cement plant. The total estimate for these additional services is 4,180,000 Mcf.

Other general possibilities contemplated by the companies are estimated at 5,000,000 Mcf.

Finally, the Companies suggest an increase for other communities, served by other systems, of from 5,466,000 (1947) to 6,000,000.

The Aggregate change from 1948 to 1960 is summarized as follows:

	1948 Mcf.	1960 (Est.) Mcf.
Canadian Western Natural Gas Company	19,609,000	25,100,000
Northwestern Utilities	12,190,000	30,740,000
Remainder of Province	5,466,000	6,000,000
Province Generally		8,200,000
	37,265,000	70,040,000
		say 70,000,000

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(1) D. B. Menzies Tr. p. 2370

The Commission's Views on Future Requirements of Natural Gas in Alberta

The Commission has been greatly assisted by the information provided by the gas distributing companies on present consumption, and by their carefully considered estimates of future requirements. The estimated increase in consumption from 37,265,000 Mcf. (1948) to 70,000,000 Mcf. (1960), or 32,735,000 Mcf. is equivalent to an increase of 2,728,000 Mcf. per year. It must be appreciated that 12 years is quite a long time over which to project estimates of consumption, and that estimates beyond 12 years would be highly speculative. In the companies' submission[1], and in the examination of H. R. Milner the view was expressed that the rate of increases estimated for 1948 to 1960, might, for the want of a better basis, be used for longer periods of time.

In the long run the principal factors affecting consumption will be population growth; the relative prices of natural gas and of competing fuels, mainly coal; and the industrial use of natural gas as a fuel and as a raw material.

Alberta is now experiencing great activity in the oil industry. This development, which appears likely to continue for a time, is having, and will have, a stimulating effect on the whole economy of the Province. The population estimates included in the submission of the gas companies are based upon reasonable statistical projections of past trends. The effect of the war on the national economy was to draw population away from Alberta, to other parts of the country more substantially affected by war-time military and industrial activity. In the immediate future the basic conditions in Alberta will prove relatively attractive; and they may well remain attractive over a longer period. It would therefore be wise to anticipate an accelerated increase in population for the Province as a whole.

The matter of the price of natural gas and of the prices of competing fuels has been fully discussed in an earlier section of this report. The Commission concludes it would be reasonable to expect that natural gas will remain a relatively cheap fuel in Alberta. The price of natural gas will then continue to provide an incentive to increased use.

The industrial uses of gas have been reviewed in the preceding section. Rapid advances have been occurring in the technology of the petro-chemical industry. Many of these advances have not yet fully exploited commercially. It is only within recent years that large supplies of natural gas in Alberta have been assured. Evidence was presented to the Commission that a number of industrial concerns are at present surveying the Alberta situation, with the object, if all conditions prove favourable, of establishing large industrial plants in the Province. A few such plants would add very considerably to the consumption of natural gas in the Province, beyond the amounts included in the estimates of the gas companies. It would be only prudent to take this possibility into account.

The gas companies estimated an annual increase of 2,728,000 Mcf. The rate of increase in consumption has exceeded 2,800,000 Mcf. over the past few years. The Commission considers that as a basis of policy some additional weight should be given to possible population increase and to possible industrial uses of natural gas. For these reasons we consider the gas companies' estimates to be conservative, and that in appraising consumption over a period of years it would be prudent to allow for an increase greater than 2,800,000 Mcf. a year.

XI. RELATION OF RESERVES TO ANTICIPATED WITHDRAWALS

Having reviewed the expert evidence on gas in place, the Commission is prepared to accept Hume's estimate of "proven and probable reserves", viz. 4.26 trillion cubic feet, as of February, 1949, as constituting the "existing and proven reserves of natural gas" in Alberta.

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(1) Exhibit No. 43 p. 2

Withdrawals of gas during a given year may be related to reserves at the beginning of the year, or at the end of the year, or to the average of reserves at the beginning and end of the year. If large additions to reserves occur during a year, the ratio of reserves to withdrawals will be high if reserves are taken as at the end of the year. For purposes of historical record the use of average reserves may be adequate, and further weight would be given to the use of the average, if any substantial part of the withdrawals during the year had come from new reserves. In making decisions affecting the rate of withdrawals, reserves at the beginning of the year would have to be taken into account.

The ratio of reserves to withdrawals during 1948 computed on each of these bases is shown below.

	Reserves MMMcf.	Net Withdrawals MMMcf.	Ratio of Reserves to Withdrawals MMMcf.
Beginning of 1948	3,722	57,547,778	65 to 1
End of 1948	4,261	57,547,778	74 to 1
Average for 1948	3,992	57,547,778	69 to 1

The Commission accepts the following statement from the Report of the U. S. Federal Power Commission,[1]

> "Reserve estimates as absolute figures in large dimensions have little significance unless they can be interpreted in relation to the volume of annual production, representing the drain upon the reserves. It is a common practice—as it is also with reference to oil—to divide gas reserves by current annual production and to designate the result as the life of the reserves. This way of expressing reserves, while understandable and useful, has basic limitations, which, unless they are clearly recognized, may lead to erroneous conclusions. New gas reserves continue to be discovered; but, on the other hand, the record of past production and indications for the future show that consumption also is following an upward course.
>
> "Even if the future reserves and future production could be estimated accurately, however, the division of the one by the other would not give the actual life period of the gas supply. The volume of gas which can be taken from the reserves in a year's time is physically limited to a somewhat definite rate of production. The deliverability of wells, moreover, declines as the fields approach depletion, and, therefore, long before the presently known reserves are exhausted, they will be incapable of meeting an undiminished rate of demand. The life of declining reserves may thus be extended by the necessity of gradually reducing production; accordingly, annual consumption may likewise be curtailed.
>
> "The availability of reserves for pipe-line marketing may also influence the life of the supply. Gas is used in the production of oil, for repressuring and pressure maintenance, and for field purposes. These requirements must generally be met before gas becomes available for other uses.
>
> "It becomes apparent, therefore, that the life of gas reserves is not subject to exact determination. As an aid in appraising the reserve situation, it is helpful, nevertheless, to relate the volume of reserves to current production."

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(1) Exhibit No. 55 pp. 45-46

The tabulation below indicates the current reserve-net production ratio in several States from which gas is "exported" (1946) and is drawn from evidence submitted to the Commission on the United States situation.

	Reserves[1] Dec. 31, 1946 MMcf.	Net Prod.[1] 1946 MMcf.	Ratio Reserves[2] to Production	Percent[3] "Exported"
Kansas	13,680,844	206,532	66.24	55.3
Kentucky	1,386,000	95,000	14.59	66.7
Louisiana	22,411,511	607,932	36.87	33.1
New Mexico	5,904,786	185,260	31.87	21.9
Oklahoma	10,735,845	655,908	16.37	35.6
Texas	86,363,459	2,097,238	44.18	18.5
W. Virginia	1,840,000	205,000	8.98	58.1
Wyoming	1,035,597	33,545	30.87	30.5
United States[4]	165,930,000	5,565,809	29.81	0.32

The Federal Power Commission has computed a reserve life index for natural gas in the United States for each year from 1919 to 1946. Over this period the index "has had a continuous rise, increasing roughly from 20 to 30".[5] The report of the United States Federal Power Commission concludes—

> "The true significance of such an index lies not merely in the number of years expressing the ratio of reserves to production but more particularly in the direction of the indicated trend. So long as the trend is either upward or stable, the reserve situation is in a healthy condition. Should there be a sustained decline in this index, however, it would signify that additions to reserves were not keeping pace with withdrawals. A leveling off of this index, or its downward trend, would suggest the need for reappraisal of this natural resource in relation to the consumer requirements to be met, and a closer surveillance of proposed extensions of pipe-line facilities. In the face of such an adverse trend, the possible needs for national defence would also become a more vital consideration."

The same view, namely, that the significant consideration is whether or not the ratio of reserves to withdrawals is increasing, remaining constant or decreasing was expressed by A. D. Brokaw in discussion of a chart included in his submissions.[6]

References, too numerous to cite, were made before the Commission to a period of 50 years. In substance these representations were to the effect that no permission for "export" of gas from the Province should be granted, unless it can now be established that, after meeting local requirements for 50 years, there will remain in the Province natural gas sufficient to meet the local demand in the year 1999 A.D.; and that the quantity of gas which might be exported should be limited to any surplus over local needs so determined.

It would be possible to give complete assurance on this point only if it were possible to forecast precisely the quantity of natural gas which will be withdrawn from reservoirs in the next 50 years, and the quantity of gas which will be added to known reserves over the same

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(1) Exhibit No. 56 p. 18

(2) Reserves are taken at the end of the year

(3) Exhibit 30 p. 15

(4) Exhibit 30 pp. 13 & 17

(5) Exhibit No. 55 Chart 3, p. 47

(6) A. D. Brokaw "Notes on Potential and Prospective Gas Reserves in Alberta". Chart 2. Proved Recoverable Reserves and Net Production of Natural Gas in the United States. Prepared by the American Gas Association and published in "Gas Facts, a statistical record of the Gas Utility Industry in the United States, 1947."

period. Such accuracy of prediction over 50 years in the future is quite impossible, and will always remain so. Consequently, unless export of gas is to be completely and permanently ruled out, the problem is one of weighing the factors affecting future withdrawals and future accretions to reserves, and of balancing the risks against the gains to be derived from disposal of gas.

Factors Affecting Future Withdrawals

The factors affecting future withdrawals are the quantity of gas flared, i.e. wasted or lost, the rate of increase in the quantity of gas absorbed in field use, i.e. consumed in drilling operations, absorption plants, etc., and the rate of increase in the quantity of gas marketed, i.e. delivered to domestic, commercial and industrial users.

Future Waste of Gas

The Commission agrees with the general view expressed in the following statement included in the evidence of W. C. Spooner:[1]

> "In the near future such gas wastage should be eliminated for these reasons:
>
> 1. The Province of Alberta, through its regulatory bodies, will prohibit waste of a valuable natural resource and thus gain in revenue.
>
> 2. In the deep gas reservoirs the producing companies will, as a matter of economy, process the gas through gasoline plants and thus greatly increase their revenue from the liquids extracted from the gas. The gas processed will either be marketed, if a market is available, or it will be returned to the reservoir. The gas processed and returned to the reservoir should not suffer a shrinkage of more than 15% of its original volume, and of course, will be available to market when the cycling is completed.
>
> 3. The oil producing area either with or without gas caps contains valuable gas reserves in the solution gas. The gas contains substantial volumes of extractive liquids recoverable through gasoline plants. The gas may be marketed as the liquid is extracted or returned to reservoir as an aid to increasing ultimate recovery. If not sold as produced, it will be marketed at a later date when markets are available.
>
> 4. With current prices of natural gas liquids and natural gas, the operators cannot afford to waste gas either before or after extraction of the liquids."

Consequently, the Commissioner is of the opinion that to assume that the ratio of waste to withdrawals would remain as it is at present would, if anything, err on the side of exaggerating the amount of waste which can reasonably be contemplated.

Future Field Use of Gas

The Commission does not feel competent to deal with the matter of field use of gas. No great error ought to be involved in the assumption that the ratio of field use to net withdrawals will remain much as it is at the present time.

Future Consumption of Gas

The rate of increase in gas delivered to users depends upon (a) the growth of population; (b) the extent to which gas continues to displace coal for domestic use; (c) increasing use of gas as an industrial fuel, which in turn depends on—(i) substitution of gas for coal, and (ii) expansion of industry in the Province; and (d) increasing use of gas as an industrial raw material which in turn depends on (i) technical developments in the field of petro-chemicals, and (ii) expansion of the petro-chemical industry in the Province. Against these factors, all of which might be expected to contribute positively to consumption of natural gas in the Province, must be set the possible substitution of other sources of energy for natural gas.

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(1) Exhibit 47 p. 34

The Commission has already examined the evidence on these points. The considered estimate of the gas companies operating in Alberta has been included. This estimate, projected to 1960, involves annual increments in sales of 2,728,000 Mcf. The Commission feels that this estimate is conservative. The Commission finds that the increase in sales over the period 1941-1948 was in excess of 2,800,000 Mcf. per year. It appears to the Commission that the price of gas may be expected to remain relatively favourable; and the Commission has been impressed by the evidence of J. R. Donald on possible additional industrial uses. For these reasons the Commission considers it would be prudent, in appraising future consumption over a period of years, to allow for an increase in consumption greater than 2,800,000 Mcf. per year.

It is certainly not inconceivable that allowing for a period of as long as 50 years the application of other sources of energy will retard the rate at which the consumption of natural gas increases, and will result in a decline in consumption.

The Commission has made no attempt to study the possibilities of atomic energy as a substitute for natural gas. The Royal Commission on Coal, 1946, secured a statement from the President of the National Research Council on "the effects which the development of atomic energy may have on the use of coal as a source of energy". Dr. MacKenzie's reply, as recorded in the Report of the Coal Commission, follows:[1]

> "The first thing that must be realized is that any opinion at present is of necessity more in the nature of a guess than a precise estimate because of the uncertainties surrounding the future of atomic energy. At the present time we know very little of the precise form future developments will take, how long it will take to make such developments, or what the cost will be, and all one can give is a consensus of opinion of a number of scientists and engineers who have been closely associated with the project. However, I must emphasize that individual opinions, particularly as to time and costs, vary widely within the group consulted.
>
> "The time of developments will be directly influenced by the amount of money and effort which the nations of the world will be prepared to devote to the work in peacetime. It will also be effected by security restrictions. The only experience we have had in development work in this field has been under the abnormal conditions of war, and if that scale of effort is maintained, which is extremely unlikely, the time taken to make developments would be relatively short. On the other hand, if the effort allotted to developments is not greater than in pre-war years, the progress will probably be very slow. The true answer is to be found somewhere between these two extremes but it cannot be expressed in a definite figure.
>
> "Again as to costs, when one talks about competitive cost figures, it can be seen that it depends again on the attitude of governments. If they support work in this field as they did in war and bear a high cost of development charges, the cost to consumers of any product would obviously be less than if private industries had to carry the development costs and added such costs to the final price; all of which makes for uncertainties in cost estimates.
>
> "What future developments will actually take place is another factor of uncertainty, and it is well known that new scientific findings and developments often affect the time and cost of materials. Taking all these things into consideration and with a full knowledge of the danger of making estimates, I would suggest the following prediction as to what might be the situation within the various time intervals suggested by you.
>
> "**Five Years**—No industrial use of atomic power, except on a pilot plant scale for purely experimental purposes.

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(1) Report of the Royal Commission on Coal, 1946 pp. 415-416

> "**Ten Years**—Limited use under special circumstances, where cost is not a consideration. Examples are: military uses; rockets to the moon; very long-range aircraft; naval uses to give effectively unlimited cruising range; supply of power in remote areas such as the far north.
>
> "**Fifteen Years**—Considerable decrease in costs. Industrial uses beginning to develop. Price probably still high enough so that effect on coal is negligible.
>
> "**Twenty Years**—Possibly costs beginning to approximate coal or hydro-electric power. New uses may very well lead to increased power consumption, and hence unlikely to decrease coal consumption.
>
> "Regarding fields of use, the following suggestions are made under the categories suggested by you:
>
> "1. Railways: Might be ultimately attractive for railways but more probably through the medium of electrification.
>
> "2. Manufacture of Electricity: It is improbable that the cost will ever fall below that of a good hydro-electric development at least until the annihilation of matter becomes feasible. Also it should be remembered that distribution costs will still remain the major cost.
>
> "3. Other Industrial Uses: These will probably be many, but the majority will probably be new processes, and hence not really competing with coal.
>
> "4. Domestic Use, including central heating: Domestic uses, other than central heating, are unlikely. Central heating is, of course, merely a question of costs. In my opinion, for low-grade uses of power, such as heat, it is unlikely to be economical in the next twenty years.
>
> "5. Ships' Bunkerage: Here increased pay-load is a factor favouring atomic power. In the future this may well be one of the first widespread uses. But there probably will be no displacement of coal to any appreciable extent within twenty years. It may be noted that the cost of converting ships would probably be high so that when this use does come into play, it may be uneconomic except for new ships.
>
> "In my opinion, the coal industry has nothing to fear in the next ten years, and very little in the next twenty. I do not think any more detailed estimate of costs can be given which has any meaning."

Evidence was presented to the Commission on the prospects for a low-cost, high Btu. gas manufactured from coal. For example, representatives of pipe-line companies agreed that if, at any time in the future, the supplies of natural gas became exhausted, adequate supplies of a comparable product from coal would be available.[1]

> "In the event the proposed pipe-line is built before any of the alternatives suggested can come into existence, and then a method is discovered for the cheap production of a high Btu gas from coal, as seems to be the most likely substitute, Alberta's coal industry would stand an excellent chance of benefitting. In such event, the pipe-line could then be used as the vehicle to transport such a substitute gas to the Coast. It would be more economical to do that than for a new industry to build a plant at the coal mines closer to the Coast and a pipe-line from any such plant.
>
> "The same would be true in the event if, at some far distant time, the natural gas in Alberta should become depleted and coal become the raw material to manu-

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(1) Exhibit No. 34 p. 12

facture a substitute for natural gas, the enormous coal fields of Alberta could be used to keep the pipe-line operating to serve Alberta and the Coast."

The subject of an alternative to natural gas, using coal, is carefully reviewed in the Report of the United States Federal Power Commission.[1] The substance of this detailed discussion is summarized in the following quotations:

> "While the prospects for obtaining an economical substitute for natural gas by established processes are not bright, the opportunities by resorting to new processes seem more favorable. Evaluation of these possibilities involves a survey of the entire field of gas manufacture as it is known today, particularly as to the prospects of synthesizing gas from coal, including processes associated with the synthesies of oil from coal.
>
> In emphasizing the critical factors of processing methods and costs, the primary importance of the cost of the gas-making raw materials must not be overlooked. Unless the cost per Btu of the coal or other basic raw material were sufficiently low, there would be no possibility of synthesizing a really cheap gas from it." . . . .
>
> "The technical feasibility of producing a synthetic fuel gas replacement from coal is the least troublesome aspect of the problem. The record is clear as to this point. The definite answer of technologists at the hearings was that a satisfactory gas of high Btu content can be manufactured whenever economic conditions sufficiently encourage its production." . . . .
>
> "A more imponderable problem, which cannot be answered so definitely as the technical one, is the economic factors which will determine the feasibility of coal gasification in competition with or as a replacement for natural gas." . . . .
>
> "In view of the nation's limited natural-gas resources as compared with coal, it seems certain that some time in the future there will be a need for a replacement gas. How rapidly this need will materialize however, is contingent upon future natural-gas discoveries, future demands for and consumption of gas fuels, and the relative prices of natural and manufactured gas. Meanwhile, the cost of manufacturing gas from coal is far above the price of natural gas.
>
> There are, however, good prospects for reducing the cost of manufacturing gas through technological development of new processes. If, through these, production costs are reduced, it may be possible to produce high Btu gas in the not-too-distant future in areas of relatively high natural-gas prices, where conditions are especially favorable to the initiation of commercial operations. Initiating such operations would assure continuously ample gas supplies for the enlarged utility service rendered by natural gas, and at the same time prevent disruptive future increases in natural-gas utility rates when natural-gas discoveries decline.
>
> Further improvements would make this supply progressively competitive with natural gas for industrial purposes. Should natural-gas supplies thereafter shrink and its price increase substantially, the availability of such a replacement supply will facilitate a gradual shift in the source of gas, with minimum interference in service or rates or in the pipe-line networks and distributing systems developed to handle gas fuel."

The conclusions, significant to the Alberta situation which could be drawn from these statements are (a) the first effect of improvement in gasification of coal, and of commercial production of high Btu coal gas, will be experienced in areas of coal production but without

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(1) Exhibit No. 55 pp. 452-453; 459; 470-471

natural gas reserves; (b) as long as natural gas remains plentiful and its price low in Alberta the prospect for substitution of manufactured for natural gas is remote; (c) however, in view of the immense reserves of coal in Alberta, the development of the process of gasification of coal is one of the factors adding to the assurance that the people of Alberta will not want for a supply of gas.

Factors Affecting Future Additions to Known Reserves

The factors affecting future additions to known reserves are the rate at which potential reserves will become "proven" and the total potential reserves underlying the Province of Alberta.

The Rate at which Potential Reserves Become "Proven"

The Commission has already reviewed the evidence on this point. Additions to "proven" reserves result from successful exploratory effort. All the evidence points to continued activity in exploration for some time, and advance in exploratory techniques suggests that the degree of success may well be greater than it has been in the past.

Unless more gas is desired for itself, it appears to the Commission that there is at present sufficient incentive to the search for oil to bring about substantial additions to known reserves of gas over the next few years. It is true that without a market for gas, operators will stay out of areas in which experience suggests gas rather than oil will be found, and they are likely to stay out of areas in which exploration costs are high and the chances of finding oil are less favourable than they are elsewhere, e.g. the Foothills.

Further, the incentive to search for oil may not always remain as strong as it is today. Increased oil production in the Province, and added costs of pushing sales into more distant markets, may bring about further price reductions in the field. Witnesses appearing before the Commission were not always prepared to agree that this would happen; and the general feeling appeared to be that the discovery of reserves of oil would itself be sufficient incentive to maintain the search. However, the possibility that exploratory effort in search of oil will diminish after a period of years cannot be overlooked. At that time, and under these circumstances, it might be desirable to offer more incentive to the search for gas.

Total Potential Reserves Underlying the Province

The Commission is of the view that all estimates of potential reserves within the Province of Alberta are "inherently speculative". The evidence on this point has already been reviewed. From the evidence, the Commission is prepared to accept the opinion expressed by Hume that potential reserves are "exceedingly large" and will utimately be proved to "exceed, many times" the presently known reserves.

The Commission is not prepared to offer any quantitative estimate of the additional reserves of natural gas which may be discovered in the next 50 years. However, a few illustrations may serve to clarify the relation between consumption, withdrawals and reserves; and to indicate the magnitudes involved if certain levels of utilization are to be supported.

In the following illustrations, total reserves at January 1, 1949, are taken at 4.261 trillion cubic feet, and the known reserves as of January 1, 1948, are estimated at 3.722 trillion cubic feet; consumption in 1948 is taken at 37,000,000 Mcf. It is assumed that consumption will represent 70 percent of net withdrawals. All calculations are for a period of 50 years.

(a) If no increase in annual withdrawals and consumption occurred withdrawals would aggregate 2.65 trillion cubic feet and consumption 1.86 trillion cubic feet. Consequently, subject to any reasonable recovery of gas in place, the estimated reserves of 4.261 trillion cubic feet would be more than sufficient, without any new discoveries or additions to reserves.

(b) If it could be assumed that consumption within the Province would increase at the rate of 3,500,000 Mcf. a year, withdrawals would total 9.02 trillion cubic feet and consumption 6.31 trillion cubic feet. The new discoveries required to provide for the increase in consumption would have to average about 100,000,000 Mcf. per year.

(c) Western Pipe Lines estimate the requirements of their line to Saskatchewan and Manitoba at 26,000,000 Mcf. in the fifth year. If an additional 26,000,000 Mcf. were immediately added to consumption, and this part of total consumption remained constant over 50 years, it would represent added consumption of 1.3 trillion cubic feet and added withdrawals of 1.86 trillion cubic feet.

In order to meet consumption in the 50th year, it is assumed that the reserves in the final year should be at least equal to the estimated withdrawals in that year, divided by the estimated weighted load factor. For purposes of illustration the weighted load factor in the 50th year is estimated at 50 percent. On these assumptions, new discoveries required to meet the increase in consumption of 26,000,000 Mcf. would average about 140,000,000 Mcf. a year.

(d) Northwest Natural Gas Company estimates the annual requirements of their pipeline to Spokane, Seattle and Vancouver at 56,000,000 Mcf. a year. If an additional 56,000,000 Mcf. were immediately added to consumption, and this part of total consumption remained constant over 50 years, it would represent added consumption of 2.8 trillion cubic feet and added withdrawals of 4 trillion cubic feet. New discoveries required to meet the increase in consumption of 56,000,000 Mcf. would average about 183,000,000 Mcf. a year.

(e) If, as under (b) above, consumption increased at the rate of 3,500,000 Mcf. per year and 82,000,000 Mcf. were immediately added to consumption, the total additional reserves, or new discoveries, required to support this level of utilization would be at least 11 trillion cubic feet; that is, new discoveries would have to average over 220,000,000 Mcf. a year.

PART III

THE CANADIAN SITUATION

The Canadian situation with respect to sources of energy is well illustrated in the following tabulation drawn from the Report of the Royal Commission on Coal, 1946.

Relative Importance of Major Sources of Energy in Canada by Regions, 1943[1]—

	Maritimes %	Ontario & Quebec %	Prairie Provinces %	British Columbia %
Water Power	8.5	37.8	11.0	37.9
Natural Gas	0.5	0.6	11.3	—
Petroleum—Canadian	—	0.1	17.5	—
Petroleum—Imported	18.8	8.9	1.5	29.4
Coal—Canadian	68.9	2.5	50.1	32.7
Coal—Imported	3.3	50.1	8.6	—
TOTAL	100.00	100.00	100.00	100.00

The more significant features of the Canadian situation evident from the table are—(a) the high proportion of energy represented by imported petroleum in British Columbia; (b) the high proportion of energy represented by imported coal in Quebec and Ontario; and (c) the Prairie Province region is the only one in which natural gas provides any significant proportion of energy requirements.

In the Maritimes natural gas is produced from the Stoney Creek field near Moncton, and is supplied, mainly to domestic users, in Moncton and Hillsborough and in some localities in Albert and Westmoreland Counties. The annual output of gas is not more than 2 percent of the consumption of natural gas in Alberta.

Letters were sent by the Commission to the responsible ministers of the Governments of Ontario, Manitoba, Saskatchewan and British Columbia, advising them of the enquiry being made and inviting them to make representations. The Government of Ontario was represented at the hearings by Mr. A. R. Crozier, Fuel Controller, Province of Ontario, who submitted evidence on the natural gas situation in his Province[2]. The Commission received a letter from Hon. J. S. McDiarmid, Minister of Mines & Resources, Province of Manitoba, setting out in formal terms the Province's position with respect to transportation of natural gas from Alberta to Winnipeg[3]. The Province of Saskatchewan was represented by Mr. J. L. Phelps, Saskatchewan Power Commission. Mr. Phelps submitted a brief statement outlining Saskatchewan's position in regard to the construction of a pipe line which would serve Saskatchewan cities and towns with gas from Alberta[4]. The Government of the Province of British Columbia did not formally respond to the invitation of the Commission but the position of the people of that province might be supposed to be adequately represented by the submission of the British Columbia Electric Company[5].

Province of Ontario

The statement of the Ontario Government[6] represented that the situation regarding natural gas in Ontario was an immediately critical one. In the view of the Government the pos-

(1) Report of the Royal Commission on Coal, 1946, p. 379
(2) A. R. Crozier Tr. p. 2012
(3) Exhibit No. 98
(4) J. L. Phelps Tr. p. 2243
(5) R. S. Davidson Tr. p. 1771
(6) A. R. Crozier Tr. p. 2068

sibility of obtaining sufficient and adequate supplies of natural gas within the Province is remote; supplemental gas currently obtained from petroleum and/or petroleum by-products is so expensive that its continued use cannot long be contemplated; the facilities for importation of natural gas from the United States are already constructed, and—"the Ontario Government must continue to seek a supply of gas to supplement the supplies which are now available from wells and fields within the Province".

The sedimentary area of Ontario, within which natural gas has been found and might be expected to be found, lies in the southwestern portion of the Province, south of a line drawn roughly from Kingston, to Wabasheen on Georgian Bay. The area is some 18,000 square miles in extent. The sedimentary column is not deep, with wells ranging from 600 to 3000 feet in depth. To date about 20,000 wells have been drilled. Past production is estimated at 435 MMMcf, and present reserves at 75 MMMcf, or a total of slightly over one-half trillion cf. Comparison of these data with the situation in Alberta indicates clearly that the sedimentary area in Ontario is relatively unproductive, and that, in relation to the very large local market for gas, it has never been and cannot be expected at any time to become a major factor in supplying the Province's fuel requirements. However, local industries in Southwestern Ontario have been built up on the supply of natural gas.

The Essex Gas Field and the Welland Gas Field were both discovered in 1889. Export of gas from the Welland field to Buffalo commenced in 1891. Export from the Essex field to Detroit, and later to Toledo, began in 1894. Termination of export from the Essex field occurred in 1904, the apparent reason being the flooding of the field. Export from the Welland field stopped in 1907, when the permit for export was cancelled by an Act of Parliament, following petitions from the people in the immediate area of the field. Behind these petitions was the decline and failure of the field. The Essex and Welland fields were both relatively small, the local market was limited, and the investment in pipe line facilities was made with United States capital, to move the gas to the larger United States markets.

In these early years, and indeed through the subsequent development of the larger Haldiman-Norfolk and Tilbury fields, no significant conservation measures were in effect. It was not until expanding local demand and heavy withdrawals during the first World War seriously prejudiced the supply position, that legislative measures were taken. Control measures in effect since that time have been directed more to restriction of use than to limitation of production.

The two most important fields in Ontario are the Haldiman-Norfolk Gas Field (1905-6) and the Tilbury Gas Field (1906-7). A pipe line was built, with Canadian capital, from the Haldiman-Norfolk field to Hamilton; and gas from the Tilbury field was piped to Chatham.

During the first World War production in Ontario reached 20 billion cf. per year. This rate of production apparently caused exhaustion of the fields. As a result of agitation, the Natural Gas Conservation Act was passed in 1917, and restrictions were placed on the sale and use of gas. Following this time the capacity of the fields declined and has never recovered.

In the period of the second World War distribution of gas increased with expansion of war industries in South-western Ontario, but production broke again. Further restrictions on use were enforced. In 1940 the Natural Gas Conservation Act was amended to provide for control of the sale of gas-using equipment. The use of gas remained under Dominion control from 1941 to 1946. In 1948, with emergency conditions prevailing, control of the distribution, and use or sale of gas was placed under the Fuel Supply Act of the Province of Ontario, and a Fuel Controller was appointed. Control is exercised through regulation of use and of equipment, rather than through regulation of production.

In 1947 the total gas distributed in southwestern Ontario was 11,368,472 Mcf., of which

7,785,921 Mcf. was natural gas and 3,582,551 Mcf. (or 32%) consisted of supplementary gases including manufactured gas, coke oven gas, oil gas, propane, and imported gas. Crozier estimated that, in 1949, 35-40% of the gas for distribution will be manufactured from oil or refinery products; and the submission of the Ontario Government states—

> "In order to meet the very serious and critical deficiency in natural gas it was found necessary in the fall of 1940 to place restrictions on the sale and use of natural gas. These restrictions and orders which still remain in force, resulted in the cutting off of approximately 13,000 domestic convertible heating units, and it now appears that unless a considerable supply of gas—possibly 6 to 10 billion cubic feet per year—can be obtained from another Province or from the United States, further restrictions may be found necessary. If such action is not taken, the natural gas distributing companies in Southwestern Ontario will be faced, within a few years, with financial disaster."

Crozier testified that the field price of natural gas is 35 cents per Mcf. and the average price to the domestic consumer (1000 Btu) is about $1.05 per Mcf. The rate increases with the quantity used. The industrial rate stays around $1.00 per Mcf. It was further represented that the cost of producing 1000 Btu gas from petroleum and/or petroleum by-products varies from $1.25 to $1.75.

The Ontario Government submission stated—

> "In fact it can be said that the two major distributing companies operating in Southwestern Ontario accepted this fact (imminent financial disaster) several years ago. In 1944 the Union Gas Company of Canada Limited commenced negotiations with the Panhandle Eastern Company to import natural gas, and in 1946-47 the Dominion Natural Gas Company Limited, the second major distributing company, began negotiations for the purchase of natural gas in the U. S. A. and the importation of same into Ontario. In 1946 the Federal Power Commission of the United States placed restrictions[1], (which are still in force) on the export of gas to Ontario. These restrictions did not, however, include the mixed gas (see above table) imported from Buffalo by the Provincial Natural Gas Company".

On the matter of importation from the United States, Crozier submitted the following evidence[2]:

> "On November 25th, 1944, the Union Gas Company entered into a contract with the Panhandle Eastern Company to purchase 5½ billion cubic feet of natural gas and to import the same into Ontario during the off-peak period May 1st, - October 1st.—I think my dates may be a little out there—each year. The Union Gas Company at a cost of 1½ million dollars completed a pipe line under the Detroit River which joined up with the pipe line completed by the Panhandle Eastern Company at a cost of $750,000, and were ready to take delivery of gas from the Panhandle Eastern Company in June, 1947. As of April 23, 1946 the Federal Power Commission, U.S.A. issued an order which in effect placed a ban on the export of gas to the Union Gas Company. As a result of this order only a trickle of gas was brought into Ontario by the Union Company from the Panhandle Eastern Company in 1947—approximately 35 MMcf. of gas—and during the year 1948 some 37 MMcf of gas, as against the quantity contracted for, namely, 5½ MMMcf. So that I think we could say this: that the contract for the gas was signed prior to the restriction.

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(1) "at all times, persons and municipalities in the United States are to receive preferential service over that to Union" Commission Order of Apr. 23, 1946.

(2) A. R. Crozier Tr. p. 2056

> Since 1947 the Union Gas Company have continued to submit briefs to the Federal Power Commission. Unfortunately, however, they have to date not received any relief and we believe it is safe to say that if the restriction placed on the export of gas to the Union Company is not lifted this year, the Union Gas Company will experience great difficulty in meeting the demand and commitments which they have made for natural gas, although this demand is being held at an absolute minimum under government control and restrictions".

From information provided by H. Zinder, Utility Consultant, Washington, D.C., on the powers and authority of the Federal Power Commission, regulations affecting the export of gas from the United States, and action taken in the Panhandle-Eastern-Union Gas Company case[1], the Commission concludes that the relevant facts can be summarized as follows:—

(a) The Federal Power Commission exercises authority over the exportation of natural gas from the United States. This authority is vested in the Commission under (i) The Natural Gas Act, 1938, and (ii) an Executive Order of the President, 1939.

(i) **Natural Gas Act, 1938, Section 3**

> "After six weeks from the date on which this Act takes effect no person shall export any gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the Commission authorizing it to do so. The Commission shall issue such order upon application, unless, after opportunity for hearing, it finds that the proposed exportation or importation will not be consistent with the public interest. The Commission may by its order grant such application, in whole or in part, with such modification and upon such terms and conditions as the Commission find necessary or appropriate; and may from time to time, after opportunity for hearing, and for good causes shown, make such supplemental order in the premises as it may find necessary or appropriate".

(ii) Executive Order No. 8202, "Authorizing and Requesting the Federal Power Commission to Perform Certain Functions Relating to the Transmission of Electric Energy Between the United States and Foreign Countries and to the Exportation and Importation of Natural Gas from and into the United States".

> "By virtue of the authority vested in me as President of the United States, and as an aid in effectuating the provisions of the Federal Power Act, approved August 26, 1935 (49 Stat. 838) and the Natural Gas Act, approved June 21, 1938 (52 Stat. 821). I hereby authorize and request the Federal Power Commission (1) to receive all applications for permits for the construction, operation, maintenance, or connection, at the borders of the United States, of facilities for the transmission of electric energy between the United States, and Foreign countries, and for the exportation and importation of natural gas to or from foreign countries, and (2), after obtaining the recommendations of the Secretary of State and the Secretary of War thereon, to submit each such application to the President with a recommendation as to whether the permit applied for should be granted, and if so, upon what terms and conditions.
>
> "The Federal Power Commission may prescribe such regulations not inconsistent herewith as it may deem necessary or desirable for carrying out the provisions of this Order."

(b) In November, 1944, Union Gas Company of Canada and Panhandle Eastern Pipe

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(1) H. Zinder. Exhibit No. 57

Lines Company entered into a contract under which the latter company agreed to deliver, during the off-season months, dump gas to the amount of 5½ billion Mcf. per year. The gas was to be stored in the Dawn field and used by Union throughout the winter months. Subsequently both companies invested substantial sums—Union Gas $1½ Million and Panhandle Eastern $750,000—in providing the necessary pipe line facilities.

(c) In January, 1945, Panhandle Eastern first filed its application for Presidential permit, authority to export under the Natural Gas Act, and for a Certificate of Public Convenience and Necessity for the facilities for the Exportation of natural gas. Hearing on these applications were held in September-October, 1945. The applications were protested by various cities and companies in the United States on the ground that Panhandle was failing to deliver all the gas needed in the United States; and should not therefore be allowed to export.

The U. S. Federal Power Commission found that the proposed facilities were adequate to render the proposed service, Presidential permit was secured, and the Commission, on April 23, 1946, issued its order authorizing export. The Order contained the following clause:

> "No deliveries of natural gas shall be made to Union during the months of January, February, March, November and December in any year during the term of this authorization. Delivery of natural gas to Union shall be curtailed or interrupted whenever, and to the extent, required for the protection of deliveries of natural gas, either for immediate consumption or for storage, to any and all of the Applicant's customers in the United States. The authorization hereby granted shall not constitute ground or justification for any refusal by Applicant to transport or sell natural gas to any person or municipality at any time during the term hereof, either for consumption in the United States by such person or municipality, or for storage, or for resale for ultimate public consumption in the United States for domestic, commercial, industrial or any other use, it being the intent of this authorization that at all times, persons and municipalities in the United States are to receive preferential service over that to Union".

(d) On the basis of the Federal Power Commission's order of April, 1946, Panhandle Eastern and Union Gas invested substantial sums—Union 1½ Million and Panhandle $750,000—in constructing the necessary pipe line facilities.

(e) In June, 1947, Union Gas requested gas on an emergency basis for from four to six weeks. The U. S. Federal Power Commission denied the request on the ground of an existing shortage of supply on Panhandle Eastern's system. In January, 1948, Union Gas asked for a modification of the Federal Power Commission's order on the ground that it has prevented delivery of gas to Union, that Union had made large expenditures on facilities and that, without Panhandle gas, Union would have to go out of business. This petition was opposed by customers of Panhandle in the United States who pointed out that Panhandle had stated in the original hearing that it did not intend to export while it was curtailing the use of gas to its customers in the United States; that shortages on the Panhandle system were common knowledge; and that the expenditures made on facilities were made with full knowledge of the conditions. The U. S. Federal Power Commission refused to modify the restrictive condition in its order of April, 1946, but said—"We shall be able to give further consideration to Union's situation in connection with the additional capacity of the Panhandle system which is now in prospect".

(f) Additional pipe line facilities are being built from Texas to Detroit, and Panhandle Eastern is adding to the capacity of its system. Whether these additional facilities will so materially change the situation in the United States as to lead the U. S. Federal Power Commission to modify its order of 1946, cannot now be determined.

In conclusion it appears to this Commission that—(i) the contract was entered into between Panhandle Eastern and Union Gas (1944) before the order approving export (conditionally) was made by the U. S. Federal Power Commission; (ii) the Natural Gas Act, 1939, indicates that the conditions surrounding extensions of pipe line facilities may not impair the ability of the company to render 'adequate service to its customers' (Sec. 7 (c)); (iii) the order of the Federal Power Commission (April 1946) contained a clause protecting users of gas on Panhandle's system in the United States; (iv) it was known that Panhandle was short of gas to supply its customers in the United States; (v) with knowledge of these conditions Panhandle and Union spent large sums in construction of facilities; (vi) when Union applied for gas (June 1947) the request was refused on the basis of the restrictive clause in the Order of 1946; (vii) subsequent petitions by Union Gas have been refused on the ground that conditions have not changed.

The Commission concludes that the main significance of the experience in Ontario, in the matter of export-import of gas, lies in the fact that the policy of the U. S. Federal Power Commission is to assure substantial protection to users in the United States before permitting export of natural gas.

Manitoba

In a letter addressed to the Commission[1] the Minister of Mines and Natural Resources, Province of Manitoba, stressed the advantages of co-ordinating the resources of Western Canada, and stated:

> "It is the hope of the Government of the Province of Manitoba that the Alberta Natural Gas Commission will find that there is sufficient natural gas to meet all the present and projected needs of the Province of Alberta and also sufficient surplus reserve to justify its exportation. If, on the other hand, the Commission decides, as a result of its findings, that it is necessary to place certain restrictions on the exportation of natural gas, it is sincerely hoped that the Commission will see fit to recommend to the Government of Alberta that the transmission and distribution of natural gas to the other Prairie Provinces be given priority over other possible export markets".

Apart from its water power resources, the Province of Manitoba is relatively poorly provided with energy sources. Some natural gas reserves might eventually be discovered in the Southwestern portion of the Province; but they are likely to be small and of local significance only. Similarly additional coal reserves may be discovered at a later time. At present the known reserves of coal are limited to the lignite deposits in an area of some 20 square miles in southwest Manitoba. Lack of local supplies and distance from producing areas result in high prices for fuel laid down in Winnipeg.

Saskatchewan

The submission of the Government of the Province of Saskatchewan stressed the importance of fuel in the prairie region, and the desirability of integrating the fuel resources of this region to the benefit of the whole, as a first consideration. Reference was made to statements contained in the Report of the Royal Commission on Coal, 1946, with respect to the extent to which natural gas might replace coal; and the view was expressed that 'geological research indicates that there is every likelihood that substantial natural gas reserves will be tapped in Saskatchewan', which gas could then be 'integrated into a well-planned pipe line system of distribution over the entire area'.

> "The Government of the Province of Saskatchewan in a submission before the Committee on Transport and Communication to the Senate of Canada, in May, 1948,

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(1) J. S. McDairmid Tr. p. 2416

> gave unqualified support to the principle of utilization of Alberta natural gas in the Prairie Provinces where the benefits in reduced living costs and increased household amenities, as well as the stimulation of industrial development, would be incalculable.
>
> The Government of the Province of Saskatchewan desires to re-affirm its support of this principle and to urge that every consideration be given the welfare of Canadians in the Prairie Provinces in deliberations regarding the use of this important Canadian Natural Resource."[1]

The statement contained in the Report of the Royal Commission on Coal, 1946, referred to in the submission of the Government of the Province of Saskatchewan, reads as follows:

> "To forecast the use to be made of natural gas in Western Canada in the next few years is extremely difficult. Natural gas reserves are clearly much more than adequate for present markets and, therefore, some considerable development in the use of the product is to be expected, but there are several lines along which such development may proceed. As an example of one of the possible lines, this Commission has had presented to it a study designed to show that, assuming adequate reserves, the transmission and distribution of natural gas from Alberta to urban centres in Saskatchewan and Manitoba is technically feasible. It is estimated that such a development, should it occur, would displace approximately 1,000,000 tons of coal annually. If, in addition, a northern line were constructed, to serve Saskatoon, North Battleford, Prince Albert, etc., a further 200,000 tons of coal might be displaced annually". (pp. 411-412)

Commenting on the same point, viz. displacement of coal by natural gas, the brief presented on behalf of the Domestic Coal Operators' Association of Western Canada[2] stated:

> "In evidence supporting the submission of Western Pipelines, it was indicated that the population to be served along a 710-mile route stretching from Gleichen, Alberta, to St. Boniface in Manitoba, with Brandon to Saskatoon and Prince Albert, is approximately 490,000. The evidence suggests too that such service would displace about 20½ percent of the prairie market for coal, or approximately 1,700,000 tons. The greater part of this would be Alberta coal".

Earlier in this report attention has been called to the fact that the sedimentary deposits of the Interior Plains extend over a substantial portion of the Province of Saskatchewan, but that the sedimentary column becomes more shallow proceeding east from the Alberta structure. The original report of G. S. Hume and A. Ignatieff[3] refers to four areas in the Province of Saskatchewan, viz. Lloydminster, Lone Rock, Unity and Kamsack.

At Kamsack, 37 shallow wells have been drilled in the Upper Cretaceous, and small quantities have been piped to a few buildings in Kamsack. Hume concludes that the field 'has no importance at present beyond small local supply'.[4]

Gas has been found in the Unity field in the Viking and Unity ends. The field appears to have an extent of 8000 acres. A number of wells have been drilled. There were three producing wells in 1947. Salt has also been found. Gas is used in the salt plant,Saskatchewan Power Commission Power plant and in the town of Unity. Hume estimates the reserve at 25 MMMcf.

The Lone Rock field has an estimated area of some 5 square miles. In 1947, four wells had been drilled, with three producing. Hume estimates the reserves at 16 MMMcf.

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(1) J. L. Phelps Tr. p. 2247
(2) V. D. Cooney Tr. p. 2278
(3) Exhibit No. 3
(4) Exhibit No. 3 p. 242

The estimated reserves in the Saskatchewan section of the Lloydminster field are set at 24 MMMcf. by Hume. With reference to the whole field Hume states—

> "In view of the absence of precise information and the shallow nature of the wells, with the necessity for long collecting lines and the attendant danger of water encroachment that might considerably reduce the reserves calculated, it is the opinion of the writers that the reserves should be regarded as sufficient only for local requirements and not counted for disposal outside the area. However, if in future drilling the zones where gas is indicated are properly tested, a sufficient reserve might be established on a sounder basis than is now possible to allow for transmission outside their local area. It is possible in the search for oil that certain gas-bearing beds have been overlooked. These may constitute a reserve not presently known."[1]

The total estimated reserves for Saskatchewan (Hume) are 65 MMMcf. These are located in four fields, which, on the information available, appear to have only local significance.

British Columbia

In reference to the sources of energy by regions in Canada, it was pointed out at the beginning of this section that British Columbia derives an unusually large proportion of her total energy needs from imported petroleum. Evidence was presented to the Commission to the effect that, although the Province has large resources of coal, wood fuel and water power, 33 percent of the energy consumed in 1947 was obtained from Petroleum[2]. The reason for this is the relative price of petroleum laid down at Vancouver. Oil is brought in at cheap tanker rates from California. Coal from Alberta or the Crowsnest to Vancouver has to bear a freight charge of $4.00 per ton.

British Columbia has the highest per capita consumption of fuel oils of any province in Canada. In 1947, industrial fuel oil consumption at 65,863,000 gallons was equivalent to 11.7 MMMcf. of natural gas or 450,000 tons of coal; domestic fuel oil consumption at 84,791,000 gallons was equivalent to 15 MMMcf. of natural gas or 578,999 tons of coal.

Considerable quantities of manufactured gas are consumed in the Greater Vancouver area. The British Columbia Electric Company, which serves that area, operates two gas manufacturing plants at Vancouver. These plants have a daily capacity of 16,300 Mcf. (460 B.T.U.), and the total production in 1948 was some 2,851,000 Mcf. Prices to domestic customers are $1.00 for the first 300 cf., 11 cents per 100 for the next 1700 cf; and 9 cents for the next 23,000 cf. Prices to commercial-industrial users are $1.00 for the first 500 cf. dropping to 8½ cents per 100 cf. between 40,000 and 200,000 cft. and 7 cents for amounts over 1,800,000 cf. Nevertheless, the number of customers and the consumption of manufactured gas have been increasing and are expected to continue to increase. In 1948 there were 48,649 domestic customers with a total consumption of 1,655,740 Mcf., and 5,401 commercial-industrial customers with a consumption of 1,563,260 Mcf.

In view of the price of manufactured gas the trend has been toward increased use of oil. In 1943, coal supplies from B. C. mines proved inadequate to meet requirements. This led to the substitution of Alberta coals. Later relatively cheap oil displaced coal. Increased consumption anticipated in 1949 and 1950 can be met by increased use of B. C. coal. These changes are evident from data supplied by the Company.[3]

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(1) Hume & Ignatieff pp 229-230

(2) Exhibit No. 69 Submission of the British Columbia Electric Company p. 33

(3) Exhibit No. 69 p. 3

		COAL			
	Oil Gals.	Island tons	Mainland tons	Alberta tons	Total tons
1943	1,206,035	65,605	48,570	1,540	115,715
1946	1,590,206	38,597	23,013	70,220	131,830
1948	4,212,000	33,139	19,960	14,601	67,700
1950 (Est.)	3,671,000	52,000	36,000	14,800	102,800

On the subject of coal consumption in British Columbia, the British Columbia Electric Company submitted evidence showing the decline in coal output in the Province.

> "It will be noted that B. C. ships 160 thousand tons to Manitoba and supplies the railroads with nearly half a million tons. Alberta ships 2.6 million tons to the three other Provinces and supplies the railroads with 2.5 million tons. The lignite coal of Saskatchewan only finds an export market in Manitoba. It will be noted that only 12 percent of Alberta production is shipped to B. C."[1]

The British Columbia Electric Company supported Northwest Natural Gas in its proposal, outlined later in this report, to pipe natural gas from Alberta to Spokane, Seattle and Vancouver. The Company submitted an estimate of the anticipated consumption of natural gas in Greater Vancouver, on the assumption that 1000 Btu natural gas was available from 1951. In arriving at the estimates for later years it was assumed that the past trend of gas customers would continue and that 'the price will be competitive with domestic and industrial fuel oil, and old and inefficient domestic coal installations but not competitive with modern domestic coal stokers and sawdust burning units'.[2]

On the basis of these assumptions the estimated position at 1955 was represented as follows:[3]

Gas purchased from Northwest Natural Gas	7,820,200 Mcf.
Daily Maximum	36,475 Mcf.
Customers:	
Domestic	76,400 Mcf.
Commercial	7,000 Mcf.
Industrial	471 Mcf.
Annual Sales	
Domestic	3,468,000 Mcf.
Commercial	980,000 Mcf.
Industrial	2,903,000 Mcf.
Total Sales	7,351,000 Mcf.

With reference to the displacement of Alberta coal through the sale of gas from the lines proposed by Northwest Natural Gas, W. C. Whittaker, Western Canada Bituminous Coal Operators' Association, stated[4]—first,

> "The Western Pipeline Company proposes to displace 1,800,000 tons of coal annually in Alberta, Saskatchewan and Manitoba", and second, "It seems safe to say, then, that gas export has the object of displacing upwards of 2,000,000 tons of Alberta mined coal, or about 25% of the production."

(1) Exhibit No. 69 p. 2
(2) Exhibit No. 69 p. 4
(3) Exhibit No. 69 Table 3
(4) W. C. Whittaker Tr. p. 2323

The comparison of these two figures would suggest a displacement of some 200,000 tons of gas sold from the line of Northwest Natural Gas. Not all of this would result from sales in British Columbia.

The brief of the British Columbia Electric Company represented that the piping of natural gas to Vancouver would greatly ease the problems of fuel supply in that city; and in examination the position was taken that—first, the pipe-line route proposed by Northwest Natural Gas was the only feasible route from Alberta inot Vancouver; and second, that the market in Vancouver was not adequate to justify building a pipeline to Vancouver alone.

The company presented statistical material in support of the contention that the economics of Alberta and of British Columbia were complementary rather than competitive, and that consequently the sale of natural gas in British Columbia generally, would have beneficial effects on the Province of Alberta.

PART IV

GENERAL

I. ECONOMICS OF PIPE LINE OPERATIONS

For the purpose of ascertaining the labor cost involved in the laying of pipe lines, the Commission obtained the following statement from the Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited with respect to the pipe lines laid by these companies in the year 1948 .

Nominal Size Inches	Outside Diameter Inches	Labor Cost per mile: $	Labor as Percent (1) of Total Cost: %
4	4½	2,300.	19.0
6	6⅝	2,630.	18.5
8	8⅝	2,890.	14.3
10	10¾	3,140.	
12	12¾	3,350.	
14	14	3,450.	
16	16	3,610.	8.6
18	18	3,750.	
20	20	3,870.	
22	22	3,970.	
24	24	4,050.	

(1) for only those diameters where actual recent experience was available.

It will be noted that the labor cost is 19 percent with respect to the 4½" line, decreasing to 8.6 percent for the larger sizes 10 inch to 24 inch.

Officials of the above companies also submitted a statement of the miles of transmission pipe line by size in place at the year end 1948 as follows:

MILES OF TRANSMISSION PIPELINE BY SIZE YEAR-END 1948

(Does not include field lines or distribution lines)

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

Nominal Diam. in Inches	Miles
2	8.314
3	8.841
4	16.287
6	40.175
8	9.396
10	65.658
12	1.474
14	16.488
16	175.948
Total	342.581

NORTHWESTERN UTILITIES LIMITED

Nominal Diam. in Inches	Miles
3	1.25
4	25.64
6⅝	30.33
8⅝	69.40
10¾	46.70
12	40.18
12¾	75.98
16	62.41
Total	351.89

The continued development of the gas reserves of the Province and the increasing demand for gas as the population and industry of the Province grows will necessitate the extension of local pipe line transmission systems. It is of interest therefore to review the factors entering into the determination of the investment to be made and the amount of gas required to be transported in order to assure the financial success of pipe line construction and service.

The investment in a pipe line transmission system for natural gas depends primarily upon (1) the volume of gas to be delivered on the peak day, and (2) the distance over which the gas is to be moved. Because of the large fixed costs involved, small volumes of natural gas cannot be transported economically over great distances.

An indication of the cost elements in pipe line investment, is provided by data reported to the United States Federal Power Commission by Class A and Class B natural gas companies for the year 1945. The report shows[1] that the total transmission plant investment of such companies is divided approximately as follows:

Item	Percent
Land and land rights	3
Measuring and regulating station structures	5
Pumping, measuring and regulating station equipment	14
Mains	78
Total	100

An analysis of the estimated costs given in applications filed before the same Commission for Certificates of Public Convenience and Necessity, which were granted during 1945 and 1946 are as follows:[2]

Diameter	Cost per Mile of Line	Cost per Inch of Diameter per Mile	Percent Increase over Average Book Costs
Inches	$	$	%
4	6,000	1,500	75
8	12,000	1,500	65
12	18,500	1,550	55
16	25,500	1,600	45
20	33,000	1,650	35
24	41,000	1,700	30

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(1) Exhibit No. 55 p. 253
(2) Exhibit No. 55 p. 254

Similar comparisons show that the average cost of compressor stations was $190.00 per horse power.

The above costs are for the year 1946. Costs have increased materially in 1947 and 1948 and may be higher still for the years 1949 and 1950. In estimating the cost per mile, Dixon of the Northwest Natural Gas Company used the round figure of $70,000 per mile as the estimated investment in the Northwest Natural Gas Company System.

It should also be noted that similar data show that fixed charges, that is charges for depreciation, taxes, and return on the investment, account for from 80 to 90 percent of the total cost of transporting natural gas. It therefore follows that there is a strong incentive for the pipe line company to seek the maximum use of the pipe line capacity and transport the greatest volume of gas possible in each and every day in order to spread the heavy fixed costs over a large volume and thereby reduce the unit cost of transportation. It is apparent that the lower the unit cost at the end of the transmission line, the lower the eventual retail charge, and the greater the market that will therefore be available in competition with other forms of fuel and energy.

Since a pipe line company will endeavour to have the use each day of the maximum capacity of the line if possible, consideration must be given to that type of the use of gas and the demand therefor which will provide for the maximum volume of gas to be transmitted daily. The variation in the daily volume of gas transported in the line is usually expressed in terms of annual load factor. The load factor is the ratio expressed in percent of the average daily demand, i.e. the volume of gas transmitted in the line, to the maximum daily demand, i.e., the maximum volume transmitted in any day in the year. The composite annual load factor then is made up of the aggregate load factor of the various classes of demand.

It is the custom in Alberta to divide the users of gas into three classifications, domestic customers, commercial customers and industrial customers. It is apparent that in the domestic classification gas required for cooking and water heating will be approximately the same in each day throughout the year. Similarly in the commercial classification, gas used for cooking and water heating in apartments, cooking in restaurants, and similar daily services will be the same throughout the year. However, in the matter of space heating, that is gas used in furnaces in homes, apartments, stores and similar buildings, the gas is required in the spring and fall in small amounts, increasing into the severity of the winter weather when the maximum demand for these purposes occurs. It is essential that a company servicing a large proportion of its customers in the domestic and commercial classifications in temperate or cold climates must provide a pipe line capacity to transmit a sufficient volume of gas to meet the demand on the coldest day in the year. This is particularly true of the Alberta systems and would be equally true of a transmission system to Winnipeg and the intervening Saskatchewan towns and cities.

The demand for gas by the industrial customers of the system, however, does not have the same characteristics. Usually an industry will require gas on an even daily basis throughout the year, subject only to fluctuations as between day and night, and between different types of processes. It is obvious therefore that a transmission system which has a substantial industrial load, will have a better annual load factor than a system which is dependent almost entirely on its sales to domestic and commercial customers. Experience in the United States indicates that with industrial customers, the annual load factor can be as high as 70 to 80 percent, whereas for domestic and commercial the load factor can be as low as 20 percent and seldom exceeds 30 percent. This experience is similar to the experience in Alberta. In the year 1948 the load factor of the Edmonton system was 38.2 percent. For the Canadian Western System in the southern part of the province, the load factor in 1948 was 50.8 percent. In large measure the difference between the two systems is due to the fact that the Canadian

Western System is servicing the Alberta Nitrogen Company plant at Calgary, which has a daily demand of approximately 9 million cubic feet per day in each day of the year or a total of approximately 3½ billion cubic feet for the year. Similarly it can be anticipated in Edmonton that the steady daily demand of an additional refinery, when built, will increase the load factor for the Edmonton system with a consequent reduction in unit transmission costs.

Load factor and cost relationships were dealt with in the report to the United States Federal Power Commission. Exhibits were filed using hypothetical cost data (basis 1945 costs) which showed the increase of cost with declining load factors below 100%, for pipe lines of lengths of 100 miles to 1500 miles and diameters of 16″ and 24″ respectively. The results of this presentation are indicated by the following figures with reference to the transportation cost per Mcf. for lines 500 miles in length.[1]

Annual Load Factor (percent)	16″ Line		24″ Line	
	Per Mcf. (cents)	% Increase	Per Mcf. (cents)	% Increase
100	10.51	—	6.79	—
90	11.59	10.27	7.47	10.01
80	12.95	23.22	8.32	22.53
70	14.70	39.87	9.41	38.59
60	17.02	61.94	10.87	60.09
50	20.28	92.96	12.90	89.99
40	25.17	139.49	15.85	133.43
30	33.31	216.94	20.90	356.85

The above tabulation illustrates the statement that for any given length and size of transmission line, delivery cost per Mcf. increases as the load factor at which the line is operated decreases. It is not suggested that the foregoing variation in cost will be applicable to lines in Alberta or lines of lesser length, but the general trend will be, in the opinion of the Commission, much the same; and the example cited illustrates the necessity in this particular climate for the development by gas transmission systems of an industrial load, if possible, on a fixed demand basis, otherwise on an interruptable basis.

Another important factor which was brought to the attention of the Commission during the course of the hearing was the reference by Dixon to the fact that for any given length of transmission line, and a given load factor, the larger the line, the less the delivery cost of gas. The United States Federal Power Commission published a table which illustrates the cost relationship as between the 16-inch and 24-inch diameter (basis 1945 costs) line as follows:[2]

Length in Miles	Average Cost per Mcf.		Percent Decrease
	16″ Line (cents)	24″ Line (cents)	%
100	3.65	2.37	35
500	17.02	10.87	36
1000	34.43	21.97	36
1500	52.83	33.88	36

Thus it is indicated that natural gas can be transported about 35 percent more economically through a 24-inch line than through a 16-inch line. Similar comparative economies would also apply also at various other load factors, and they would be even more pronounced in respect to larger lines of 26-inch and 30-inch diameter. The United States Federal Power Commission report further states—

"the industry presentation clearly shows that a high-load factor is relatively more

(1) Exhibit No. 55 p. 260
(2) Exhibit 55 p. 253

> important economically for a smaller diameter pipe-line than it is for the large capacity lines which are increasingly used in long-distance transportation of natural gas. . .
>
> "It is likewise true that, within broad limits, the size of the pipe line is a more important economic factor affecting transportation cost than is the load factor attained in its operation. For example, the industry exhibit reveals that a 24-inch line operated at 60 percent load factor will have approximately the same transportation cost per Mcf. as a 16-inch line operated at 100 percent load factor. Under these circumstances it would seem evident that in striving for low-cost pipe-line transportation, appropriate consideration should be given to the important economics inherent in a large diameter line rather than giving undue emphasis to the advantage of extremely high-load factor operations."

The foregoing serves to emphasize that in Alberta it is essential in the interest of both domestic and commercial users that industrial loads be added to the pipe line demand in both systems in the province. On the other hand, our excessively cold winters make it possible that industrial load when added to the demand will be required to accept a contract on an interruptible basis, that is to say, when in cold weather the domestic and commercial requirements approach the capacity of the lines, the industrial load will, of necessity, be decreased and in some cases be eliminated in order to maintain the delivery of ample gas to the domestic and commercial customers. It is obvious that such an arrangement is not an ideal one for an industry, and industry establishing in Alberta will not look with favor on an interruptible contract basis of supply. It follows therefore that the transmission systems built, and to be built, in Alberta should be of such capacity as to provide not only for the full domestic and commercial demand but if possible for the maximum demand, at the same time, of the industrial load.

In connection with the above problem, attention should be drawn to the alternatives to meeting the demand of the industrial customers. A number of suggestions have been followed in the United States, including the use of terminal storage facilities. In a number of instances, it has been possible to store gas in the summer months and use the full capacity of the transmission lines. The gas so stored is placed in fields near to the industrial centres of demand and in the winter months when the capacity of the line is required to meet the domestic and commercial demand, industries have been able to obtain their requirements from the stored gas. During the hearings reference was made to the fact that since 1930, except for a short period between 1940 and 1945, gas produced during the summer months in Turner Valley has been transmitted to the Bow Island Field and stored. Subsequently, during the winter months when the capacity of the lines from Turner Valley to Calgary have been in use, the additional requirements of the industrial load in Calgary have been met by gas transmitted from Bow Island to Calgary, through the Canadian Western main line. It has been suggested that in Northern Alberta gas can be stored in the Viking field during the summer months, using for this purpose surplus gas available in the solution gas fields in the oil areas. In this way, a further supply of gas will be built up for the northern system and there will be additional pipe lines to take care of the high demand during the winter months. As will be noted in another part of this report, this could be one advantage that may accrue from the building in Alberta of a 'grid' gathering system.

II. SPECIFIC PIPE LINE PROPOSALS(1)

Western Pipe Lines

Osler, Hammond & Nanton Limited, a company with head office at Winnipeg proposes to incorporate a company to be known as "Western Pipe Lines", and to construct and operate a natural gas pipe line from Alberta to a point or points near the boundaries of the cities of Winnipeg, and St. Boniface, in the Province of Manitoba. The Company also contemplates the construction of branch lines in order to make natural gas available to the cities of Saskatoon and Prince Albert, in the Province of Saskatchewan, and to any other city, town or village to or near which any of the said pipe lines may pass.

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(1) The Summary Statements in this Section follow the representations of the pipe line companies, as they were made before the Commission.

It is proposed that the main line of the company would follow in a general way the main line of the Canadian Pacific Railway from a point near Gleichen, Alberta, to Winnipeg, a distance of about 710 miles. The Western Section would consist of 375 miles of 24 inch pipe line and Eastern Section 335 miles of 22 inch pipe line. The branch line to Saskatoon and Prince Albert would be composed of about 120 miles of 12¾ inch pipe line as far as Saskatoon and thence 85 miles of 8⅝ inch pipe line to Prince Albert. The pipe lines would be designed to operate at a maximum pressure of 750 pounds per square inch. Three compressor stations would be required, totalling about 20,000 brake horsepower. The population served by the proposed system is estimated at approximately 490,000. Sales in the fifth full year of operation are estimated at twenty-six billion cubic feet with a maximum daily demand of about two hundred and eight million cubic feet.

The capital cost of the proposed pipe line project is estimated at about $49,000,000. While Western Pipe Lines does not propose to engage in the distribution of natural gas, it is estimated the total capital cost of the distribution system it would supply at about $26,000,000.

Mr. Julian Garrett representing Western Pipe Lines, stated in evidence that the estimates on which the project was founded provided for the payment at the intake of the transmission line near Gleichen of a price for gas of 10c per Mcf. It was anticipated that the wholesale price for gas delivered by the transmission line at the town and city gates would be 54.89 cents per M.C.F. The retail rates to consumers were estimated to be Domestic-64.2 cents per Mcf; Commercial-48.4 cents per Mcf; Industrial-38.7 cents per Mcf.

The Western Pipe Lines estimates did not provide for the construction of a pipe line gathering system in the Province.

Northwest Natural Gas Company

Northwest Natural Gas Company proposes to build a natural gas pipe line system connecting the gas fields of Alberta with the cities of Vancouver, Seattle, Portland, Spokane, and the Smelter at Trail. The main line, 24 inches in diameter with a maximum capacity of about 200 million cubic feet per day, would start at a point near Macleod, Alberta, follow more or less the main highway through the Crows Nest Pass to Kingsgate, British Columbia, thence southwesterly to a point near Spokane where a branch line would be built to Trail. From near Spokane the line would proceed through Steven's Pass to a point north of Seattle with branch lines of 20 inch diameter to Vancouver, Seattle and Portland. The gas will assemble at point near Macleod. The exact location of the gathering system for Northern areas cannot now be precisely determined, but in any case there must be a line from Macleod to Jumping Pound by way of Turner Valley which may extend north to Leduc. A line would be built east from Macleod to Taber with branches from there to Foremost, Princess and possibly Kinsella. There will be about 140 miles of 24 inch, 290 miles of 20 or 22 inch, 50 miles of 16 inch, 110 miles of 8 inch, 100 miles of 6 inch and 300 miles of 4 inch, totalling about 1,000 miles of pipe line to be built in Alberta.

The Company will sell gas to the local distributing companies for resale in the cities to be served as above mentioned and to other consumers along the line. It is estimated that after two years the line will have an annual input of approximately 60 billion cubic feet. It is expected the gas will be sold at an average price of 38 to 40 cents per Mcf. The gas purchased over a twenty-five year period will wield a minimum of 172 million dollars to producers in Alberta.

The total cost of the entire project is estimated at present prices to be about $100,000,000 of which $40,000,000 will be for the Canadian part and $60,000,000 for the United States part.

As intimated by the Company in letters to the Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited, the Northwest Company was prepared to enter into contracts with the Alberta Distributing Companies for the purpose of making available to them their requirements from the gas gathered and in transmission through the Province; thus assuring a supply of gas for the Alberta consumers as and when required.

The route for the Northwest Company pipe line was selected after careful consideration of the possible Canadian routes. D. S. Goodbody, the engineer employed to locate the pipe line testified before the Commission that he found the terrain too rough for any economical construction of a line directly across British Columbia to Vancouver. Any line from Alberta through the Yellowhead or Kicking Horse Passes would have to be laid through the Fraser River Canyon where the available areas are now occupied by the railways and the highway. He admitted the line could be built above the railway and highway but only at tremendous cost and it would be a hazard for the railroad.

Together with engineers of the B. C. Electric Company, Goodbody surveyed[1] a route in Canada from Yahk to Vancouver. He estimated a pipe line over the proposed route would be 675 miles in length and cost $67,500,000 as contrasted to a line over the selected route, 574 miles, at a cost of $37,400,000. He further pointed out the deep snow on the height of land, lack of roads, and snow slides would make maintenance of the line exceedingly expensive if not physically impossible.

Frank McMahon Project

Frank McMahon of Calgary, made a submission to the commission on behalf of a group composed of Pacific Petroleums Limited, its subsidiary, the Peace River Natural Gas Company Limited, the Pacific Western Oil Corporation, of Los Angeles, California, the Tidewater Associated Oil Company, of San Francisco, California, the Sunray Oil Corporation, of Tulsa, Oklahoma, and Eastman Dillon & Company, of New York, and associated corporations and individuals. He stated that the group he represented planned to incorporate a company to initiate and carry out the project of transmitting Alberta natural gas to Vancouver and intervening points and the United States cities in the Pacific northwest.

He stated that the members of the group, in association, and in their individual capacities, were carrying on extensive oil and gas exploration operations in Alberta. He referred particularly to the development of gas reserves in the Peace River area where the group was carrying on intensive exploration under the supervision of S. E. Slipper, and to the extensive holdings of the group under development in the vicinity of Lesser Slave Lake and the Athabaska River.

On cross-examination McMahon made it clear that his group preferred to construct a line by an all-Canadian route. He stated that a number of Canadian routes had been surveyed[2] and found feasible. One prospective route mentioned was that from the Peace River through to Prince George, British Columbia, and then to Vancouver; another from the northern part of Alberta to Edmonton and through the Yellowhead Pass to Vancouver; the third from the northern part of Alberta through Edmonton to the southern part of the Province and then west to Vancouver. McMahon stated that his reply to suggestions made at earlier hearings of the commission to the effect that an all-Canadian route to Vancouver was physically impossible, prohibitive in cost and difficult if not impossible to maintain, was that his group was prepared to carry out the project. He pointed out that the cost of the Canadian route may or may not

(1) "Survey" is here used in the sense of a general view or inspection.

(2) "Survey" is here used in the sense of a general view or inspection.

be higher than the route suggested via the United States, but in any case the cost was not prohibitive, the engineering was not only possible but practical and the pipe line system could be adequately and efficiently maintained.

McMahon stated that the final decision as to the best or most beneficial route or routes to be followed will be governed by the location of the gas fields in the province from which the gas is to be drawn. He further stated that the cost of the pipe line would depend on the route and the estimates varied from $50,000,000 to $100,000,000.

An Integrated Gathering System

In his submission on behalf of the Canadian Western and Northwestern Utilities Companies, H. R. Milner referred to the advantages that would accrue to the Alberta companies and also the companies interested in the export of gas by the construction in the Province of a grid or integrated gathering system for gas. The Commission requested Milner to submit any further comments he felt able to make in regard to the proposal he first made. Milner submitted a map of the Province, on which he marked a proposed pipe line system, together with a written statement. He pointed out that his proposal was tentative as to the location of the lines but that the Alberta Companies were prepared, when the time comes, to undertake construction and operation of such a system.

Milner proposed that in addition to the existing transmission lines of the Alberta Companies a line be constructed from Redwater to Edmonton, Edmonton to Red Deer, with a lateral to Leduc field; Red Deer to Calgary, with a lateral to Jumping Pound extending to Banff. At Calgary the line would tie in with the Canadian Western main line from Calgary south to Bow Island. From Bow Island lines would be constructed east to the Saskatchewan border as a feeder to the Western Pipe Lines system and north to tap the Princess field. From Macleod a line would be constructed west to the British Columbia border through Pincher Creek as a feeder line to the Northwest Natural Gas Company system with a lateral to the Cardston area.

He suggested that where the capacity of the existing lines proved insufficient that additional lines be constructed parallel to or in substitution for the same.

The proposal made by Mr. Milner was communicated to the officers of the North West Natural Gas Company for their comment due to the fact that that company had, in its submission, outlined the proposal of the company to construct on its own behalf a Province wide gathering system for the supply of gas required for the transmission line to the northwest United States.

A. F. Dixon, the President of the Company, submitted a written reply. He pointed out that the proposed lines would make some gas available to a pipe line system going to the east but little or none, except from Pincher Creek, for a line to the West. In conclusion he stated:

> "The proposed lines would make a system adequate to serve Calgary, Edmonton, and other communities in Alberta, but would be wholly inadequate to gather gas for export. More pipe lines will be required for gathering the gas for export than all of the present and proposed lines shown on the map presented."

Dixon added that he would be prepared to sit down with the engineers of the present Alberta companies and work out a plan for gathering gas both for the Province and for export.

It appears obvious to the Commission that if the market for Alberta gas were expanded by the construction of transmission lines either east or west or both ways, it will be necessary to build extensive gathering lines to or between many of the gas fields. Milner outlined in his statement the advantages which he saw in the construction of an integrated gathering system as follows:

1. The elimination of unnecessary pipe line duplication, with resulting economies in capital and operating costs.
2. Additional assurance against interruption of the supply to the communities already served in the Province due to mechanical failure.
3. Making available certain fields such as Viking-Kinsella, Turner Valley, and Bow Island for the storage of gas which would otherwise be flared.
4. Permit the closing in of dry gas fields and the substitution in the provincial market for long or short periods of gas from oil gas fields.
5. Certain communities not now served would be able to obtain natural gas.
6. In all probability the construction of the additional transmission facilities can be proceeded with in stages as required.
7. The Scheme contemplates tie-ing in practically all the available gas fields.
8. The system can be equally available for the export of gas east or west, or both.
9. It would permit the integration of fields and the establishing of differential prices for local use and for export.
10. It would assure the protection of local requirements since local distributing companies cannot afford to jeopardize either their own interests or those of their consumers.

III. NATURAL GAS IN THE SERVICE OF THE RURAL POPULATION

The Alberta Federation of Agriculture, representing all major farm organizations and considerably more than 50 percent of the population in the Province, specifically requested in their submission that, in considering the future requirements of natural gas in the Province, consideration be given to—first, the use of by-products of the petroleum and natural gas reserves, particularly propane, and, second, the possibility that natural gas might become a source of power in rural areas.

Propane

The liquefied petroleum gases, i.e. butanes and propane, may be extracted from the wet gas either to facilitate transportation of the dry gas or for the uses to which they themselves may be put.

With regard to the problem of pipe-line transmission of gas, the U. S. Federal Power Commission states.[1]

> "Natural Gas which is to be marketed must be sufficiently stripped of its liquid-forming fractions to prevent condensation in transmission lines at the pressures and temperatures encountered. The condensation of these liquids during transmission causes difficulty with regulators, meters and other equipment. With the high pressure now utilized in present-day pipe-line systems, the gas must be stripped very low, —down to 0.2 gallons per thousand cubic feet or less. With few exceptions, therefore, all pipe-line gas, whether its source be from oil wells or gas wells, is first processed through a gasoline extraction plant".

The U. S. Federal Power Commission also refers to the increasing use of liquefied petroleum gases as fuel for domestic and commercial purposes.[2]

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(1) Exhibit No. 55 p. 92
(2) Exhibit No. 55 p. 91

> "Liquefied petroleum gases (LPG) are also becoming an increasingly important category of products of the natural gasoline industry. Because of their extreme volatility and consequent problems of transportation, these hydrocarbons, until a few years ago, were either wasted or were used as boiler or plant fuel. Now, with the development of improved means of transporting and handling them under pressure, they are extensively used as fuel for domestic and commercial purposes in areas where natural or manufactured gas is not available."

Production of liquid petroleum gases by gas utilities in the United States increased from 1,529 million cubic feet in 1940 to 15,339 million cubic feet in 1947, i.e. by more than 10 times.[1] In 1947, 7,280 million cubic feet or approximately half of the quantity produced, was sold to ultimate consumers, the remainder being used for mixing or producing other gases. In the same year, 4,559 million cubic feet, or more than half the sales to ultimate users, were sold to residential customers.[2] Between 1946 and 1947 the number of residential customers increased from 111,000 to 211,200, or 90.3 percent; volume of sales increased from 2,533.3 million cubic feet to 4,559 million cubic feet, or 80 percent. In 1947 sales revenue per Mcf. averaged $1.83.

In evidence before the Commission, A. F. Dixon pointed out that pipe-line developments in Alberta would result in increased production of liquefied petroleum gases. He referred to increased utilization in the United States.[3]

> "They use it a great deal in California now and West Texas, just as gasoline. They have a strong tank in the back of a car, a truck especially; they never use it in a private car as far as I know; they use it just exactly as if it was gasoline except you have no carburetor and it feeds directly into the engine . . . . In Pennsylvania there is one company, the Atlantic Gas Company, that I did a little work for years ago, which now, I understand, has 20,000 farms supplied with this butane and propane. They do not carry it around in the bottles like it is often done, but they are putting it in a tank on the farm and every two or three months they have a truck come around and fill this tank, and the pressure of the gas in the tank puts it into the farmhouse and it acts just like piped gas . . . . It is also used a great deal in Northern Louisiana in the rural districts".

Dixon also discussed the use of propane to serve small towns and villages.[4]

> "You need to have a population of at least six or seven hundred to put in any plant of that order. If it becomes smaller it is best to put in a tank in each house. . . Very often they might put in a plant using propane when you can pipe it in with very small pipes with no supervision at all. If necessary it is just like it was being put into a single house, only goes in a series of small pipes and that has proved very satisfactory in very small communities".

Later Dixon stated[5] that in towns in the United States served with natural gas, propane and butane begin to compete with natural gas if the pipe line to separate residences has to be carried more than 200 yards. Beyond that it is cheaper for the customers to install a propane tank.

For the Alberta situation the butanes will not be considered as they flow at higher temperatures than propane and therefore are not considered as favourable for general use for fuel in Alberta as propane, which flows readily at low temperatures.

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(1) Gas Facts American Gas Association, 1947 p. 53

(2) Gas Facts American Gas Association, 1947 p. 2

(3) A. F. Dixon Tr. p. 820

(4) A. F. Dixon Tr. p. 986

(5) A. F. Dixon Tr. p. 1038

A brief outline of the process and equipment used to extract petroleum gases from crude oil and gas mixtures follows. First, there is the production of an oil well producing a mixture of crude oil and wet gas from the underground reservoir to the surface of the ground. At the surface, this mixture is led into a gas trap, which is a separator that allows the crude oil to flow to the bottom and pass to the oil storage. The wet gas comes off the top and is piped to the gasoline absorption plant. This wet gas contains natural gasoline, liquefied petroleum gases and 'dry' natural gas. In the gasoline absorption plant, the gas flows through absorption oil which removes the natural gasoline and liquefied petroleum gases, while the dry or natural gas comes off the top where it may then enter a distribution pipe line for general use.

The absorbing oil, now saturated with hydrocarbons, is piped to a still. There the combination of natural gasoline and liquefied petroleum gases is boiled off in the form of 'wild gasoline'. The absorption oil is then returned to the top of the absorber. The 'wild gasoline' continues to the stabilizer towers where natural gasoline is removed from the bottom as a finished product, and a mixture of liquified petroleum is drawn off the top. The liquified petroleum gases drawn off the top can be further treated to break them into two parts propane and butane. Propane is a slightly lighter liquid than the butane. Propane may be sold by weight or by volume. A gallon of propane weighs 5.7 lbs. and is equivalent to 44 cubic feet. The heat value of propane compares with other fuels as follows:

Propane	one pound	=	21,600 Btu.
Coal	one pound	=	13,000 Btu.
Natural Gas	one cubic foot	=	1,000 Btu.
Electricity	one KW hr.	=	3,412 Btu.

Utilization

Information obtained indicates that propane is a satisfactory fuel for many uses, such as domestic gas range, refrigerator, water heaters, space heating, gas engines, tractors, trucks, buses and other uses. Its use is particularly convenient for farms, camps, resorts, small towns and villages not tributary to main or branch gas lines.

Production

The production of propane in Alberta is comparatively new, and only one propane plant is operating at Turner Valley in the southern part of the Province. As it has only recently commenced operations sufficient time has not elapsed to provide adequate distribution to allow for capacity production. Another absorption plant is being undertaken at Leduc in the central part of the Province. In accordance with oil production and refining in the Province propane may be produced in quantity. As indicated in the evidence of J. E. Barber, President of Western Propane Limited,[1] he states,

> "The absorption plants definitely under construction and in operation can supply more propane than the prairie provinces could possibly use. Further, if propane were free the distribution of it would make it non-competitive with natural gas and that when handled in small quantities, as in 100 pound containers, more than 75 percent of the cost of propane is in the cost of distribution and handling."

The Commission also received an opinion to the contrary that on a per capital consumption basis for domestic users equal to that of the U. S. A., it would appear that present production facilities are considerably short of further requirements. No opinions have been expressed to the Commission indicating a shortage of the gas mixtures from which propane is extracted.

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(1) J. E. Barber Tr. p. 2492

Distribution

The distribution of propane is carried out in much the same manner as gasoline is presently being distributed, excepting that trucks and tank cars must be equipped with pressure pumps, and storage containers must be of sufficient strength to withstand the necessary pressure within the retainers. It is conceded that the small towns, villages, camps, resorts and farm communities isolated from existing and proposed pipe lines for the distribution of natural gas offer adequate opportunity for tremendous increases in distribution and consumption of propane throughout Alberta and the other Western Provinces. The present distribution of propane represents approximately 3,000 gallon per day. The production capacity of the Turner Valley plant is 20,000 gallons per day. The Leduc plant will add to the producing capacity. The major factor in increasing distribution and consumption lies in more economical distribution through a greater realization and appreciation of propane as a convenient and efficient fuel, and its ability to compete with fuels other than natural gas.

Propane is at present being distributed to farm customers at 8 cents per lb. where the storage capacity is less than 100 lbs.; and at 5 cents per lb. where the storage capacity is over 100 lbs.

Rural Electrification

The City of Edmonton, through their submission given by D. B. Menzies[1] stated—

> "On straight calorific Btu's per pound of coal and per so much of gas, and not allowing for any efficiency in the plant as between one fuel and another, we feel we could have saved One Hundred and Forty Thousand Dollars had we burned gas in our plant (electric power plant) last year instead of coal".

Harry O. Davis, in his submission on behalf of the City of Medicine Hat,[2] makes this statement—

> "I may say we are able, by the use of our natural gas and plant refinery—we are able to produce power on the bus in the power plant at approximately 1/4 of a cent per Kilowatt hour, making us in a position to compete quite readily with present day hydro installations where capital charges are high."

Included in his evidence, commenting in respect to contracts with customers for large block of power— ". . . say from 500 to 1000 horsepower, we have an additional contract rate which includes energy supplied as low as 1/3 of a cent per Kilowatt hour, with a straight demand charge of 1/2 cent per KWH added to that low energy rate".

The Commission was further impressed with Davis' evidence when commenting on the new installation of a turbine generator and the added economy of the modern machines and boilers when he stated—

> "For instance, right now in order to explain that a little clearer, we are using at the rate of possibly between 19 and 20 cubic feet of gas per Kilowatt hour produced. Due to the installation of this modern plant when it gets completed, we will make a reduction there probably down to between 15 and 16 cubic feet per Kilowatt hour. I would say we can compete with anyone in Western Canada and a good many in the east, in electric production".

Speaking from memory, Davis stated,—"I think our absolute net profit, after paying all capital charges, municipal taxes and providing for reserves, taking 15 percent of the gross earnings, was in the order of $98,000.00. I would say altogether it would be over $135,000.00

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(1) D. B. Menzies Tr. p. 2389

(2) H. O. Davis Tr. p. 75

in the electric alone". His evidence also pointed out that the power plant had paid $100,000.00 in municipal taxes.

The above evidence indicates the effect that natural gas, at low cost, has in creating industry and in rendering a most important service to a community.

With reference to the use of natural gas for generating power in rural centres, A. F. Dixon offered the following evidence.[1]

> "I would think then that for rural electrification the next thing (to hydro) is small gas engines which would take the place of long distance transmission lines, where it is conveniently located along the pipe lines, where they could then generate locally and transmit without having to lose a great deal of their power in bringing it long distances and with all attendant expense of the high line. That type of generation is adapted to these smaller consumption areas. . . . .
>
> Q. Are the pipe lines which you have had something to do with, are they actually being tapped, as it were, along the way for this type of rural electrification plant?
>
> A. No, the people wanted to do it and were talking about it but it was all pre-empted by the larger plants and the high lines, so that originally there was a great deal of that type of thing in the smaller communities where there was gas available, and then a group of the big holding companies,wanting to take everything in sight, swept away and took away all of the small generating plants and today they have to be connected with the high lines, a thing that is in my opinion highly uneconomical. They should have kept their local plants.
>
> Q. But in any event, the existence of the small electrification plants provided a basis of competitive price upon which the high line transmission electricity was delivered to these towns?
>
> A. Yes, and maybe the threat of being able to do it, is better than to do it.
>
> Q. It is possible, however, just keeping in mind your particular lines, if they are installed, would it—be possible to provide for rural electrification plants, say, every couple of hundred miles along your line, or every hundred miles along your lines?
>
> A. Very easily, and it takes very little operation, or very little cost of operation to furnish electricity if you are getting gas off a pipe-line . . . .
>
> Q. Could you say that this type of electrification for establishing power is very close to competition to high line transmission?
>
> A. When the capacities are small where you do not need much electricity. If you need a great deal, of course, the high line is the better method."

Evidence on transmission costs has been reviewed in an earlier section.[2] The capital costs of laying pipe lines is exceedingly high, and the Commission considers that unless the large transmission lines were laid quite close to any rural centre, the cost of carrying the gas from the main line to the centre would tend to be prohibitive. This cost would be largely eliminated if the rural centre were situated on top of a source of gas supply.

The economy of providing electricity to farms from power generated in local plants using natural gas, or from high voltage transmission lines energized by hydro plants or large centralized fuel plants, depends on the relative cost at the point from which farm distribution lines would originate. The Commission has been unable to go into this matter fully. In particular, accurate information on generating costs in relatively small plants using natural gas, is not available.

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(1) A. F. Dixon Tr. p. 979

(2) Economics of Pipe Line Operations.

In view of the increased urban demand on present power facilities, and the marked desire on the part of rural people for electrical service, the Commission feels that a detailed survey should be made to determine the extent to which cheap natural gas can be made a factor in developing and extending rural electrification.

SUMMARY AND CONCLUSIONS

(A) To investigate the existing and proven reserves of natural gas in the Province of Alberta.

(1) Estimate of the "Existing and Proven" Reserves

From the evidence before it, the Commission is of the opinion that the existing and proven reserves of natural gas in the Province of Alberta, as at February, 1949, amount to 4.26 trillion cubic feet.

Dr. G. S. Hume, Geological Survey of Canada, estimated the 'proven' and 'probable' reserves of natural gas in Alberta as 4.26 trillion cubic feet. The Commission was impressed with the measure of support which Dr. Hume's estimates received from other geologists, and we are of the opinion that Dr. Hume's categories of 'proven' and 'probable' reserves can properly be included within the meaning of the terms "existing and proven reserves of natural gas".

(2) The Problems of Accurate Estimates of Reserves in Place.

It is evident that the quantity of natural gas in an underground reservoir cannot be precisely determined, and any estimate of the reserve in place is necessarily subject to a margin of error, plus or minus. No measure of the degree of accuracy of the total reserve estimate of 4.26 trillion cubic feet is possible.

The accuracy of estimate depends, to a considerable extent, on the completeness and accuracy of the information available. In some fields in Alberta accurate records of early production have not been kept; in others, development has been so recent that current information is incomplete. Estimates of reserves in place in particular fields will change, up or down, as and when production proceeds and more complete and accurate information regarding reservoir conditions becomes available.

(3) The Problems of Recoverability and Availability of Reserves.

In appraising the significance of estimates of reserves of natural gas in the reservoir, consideration must be given to the ultimate recovery of gas from the field and to the availability of the gas over the years.

The quantity of gas recovered is always less than the quantity in place. The pressure at which the field will be abandoned is one factor which affects the quantity of gas recovered. The quantities included in the total of 4.26 trillion cubic feet have been established to an abandonment pressure of 100 p.s.i.a. There are other factors, for example water encroachment, which may reduce the quantity ultimately recovered. The proportion of the gas in place which will be recovered and marketed is different for 'dry gas', 'wet gas' and 'solution gas'. The total estimated reserve of 4.26 trillion cubic feet includes 'dry gas', 'wet gas' and 'solution gas'. The ultimate marketable, dry, clean gas, which could reasonably be expected is estimated at 3.49 trillion cubic feet.

The availability of gas, particularly from 'gas-oil' fields, depends on reservoir engineering practices and conservation policy. For example, if gas is used for pressure maintenance it will not be available, for market, until some time has elapsed. Appropriate practices and policies can only be determined after a period of production experience. In some fields in Alberta, for example Leduc, it is not yet possible to determine the rate at which gas may be available for delivery to pipe lines.

(B) To enquire into and estimate the potential reserves of natural gas in the Province of Alberta.

(1) Estimates of Potential Reserves Speculative; but these Reserves are Undoubtedly Large.

From the evidence before it, the Commission concludes that all estimates of potential reserves are "inherently speculative", and that no useful purpose would be served by attempting any quantitative estimates of the potential reserves of natural gas in the Province of Alberta. At the same time, the Commission is prepared to accept the judgment of Dr. Hume and of the other geologists who supported him, that the potential reserves are "exceedingly large" and will ultimately prove "to exceed, many times" the present existing and proven reserves.

(2) Substantial Additions to known Reserves may be Expected in the Next Few Years.

There would seem to be little doubt that substantial additions will be made to "existing and proven" reserves over the next few years.

Exploration in Alberta is directed toward the discovery of oil. Gas may be found where there is no oil. If oil is found gas will be associated with it.

During 1948, the record of exploratory activity in extension of lease holdings, geophysical surveys, drilling of wildcat and development wells, and actual discovery of gas and oil, is impressive. There is no evidence of any decrease in the intensity of effort; on the contrary, increased activity throughout 1949 can be confidently anticipated. The Commission cannot believe that the companies engaged in exploration are mistaken.

Looking further ahead, the evidence on the area and depth of the gas-bearing sedimentary rocks in the Province, and on the extent of those sections of the Province which are as yet untested or only partially tested, suggests that further additions to known reserves are dependent only on investment and effort in exploration and development.

(C) To enquire into the present domestic, commercial and industrial consumption of natural gas in the Province of Alberta.

(1 Withdrawal and Disposition of Natural Gas, 1948.

The Commission finds that the withdrawal and disposition of natural gas in 1948 was as follows:

ALBERTA NATURAL GAS, 1948

Quantities in Mcf.

Gross withdrawals	61,034,698
Deduct gas repressured, Turner Valley	3,135,821
Deduct gas repressured, Bow Island	351,099
Net withdrawals	57,547,778
Marketed	38,350,808
Field use	6,734,570
Shrinkage	2,714,264
Flared, including meter differences	9,748,136
Total disposals	57,547,778

Note: More gas was taken from Bow Island field in 1948 than was stored. The withdrawals appear as part of the total net withdrawals and the figure above is the quantity supplied from Turner Valley.

Gas used by industries at Medicine Hat-Redcliff is considered as marketed even though used by producer.

Shrinkage is applied only to gas processed. Gas that was not processed would have had some shrinkage if processed thus reducing apparent amount flared.
Flared includes metering differences of 392,919 of which 391,855 was within Madison system and was about 1⅓ of handlings; a measure of reliability of metering. Flared gas does not include gas lost through Atlantic No. 3 well in Leduc field which was out of control. That loss may have been of the order of 25,000,000 Mcf.

(2) Sales of Natural Gas to Users, 1948.

The Commission finds that the consumption of natural gas in 1948, as measured by sales of gas to users was as follows:

	Mcf.
Domestic	12,593,000
Commercial	8,668,000
Industrial	10,538,000
Total Classified Consumption x	31,799,000
Unclassified#	5,466,000
TOTAL CONSUMPTION	37,265,000

x Sales of Canadian Western Natural Gas Limited and Northwestern Utilities Limited.
# All other sales, 1947.

(D) To estimate the future requirements of natural gas for domestic, commercial and industrial purposes in the Province of Alberta.

(1) A Conservative Estimate of Natural Gas Consumption in Alberta, 1960.

The following estimate of natural gas consumption in the Province in 1960 was submitted by the Canadian Western Natural Gas Company Limited, and Northwestern Utilities Limited:

	Mcf.
Canadian Western	25,100,000
Northwestern Utilities	30,740,000
Remainder of Province	6,000,000
Province Generally	8,200,000
	70,040,000
say	70,000,000

The estimate of 70,000,000 Mcf. for 1960 compared with the consumption of 37,265,000 Mcf. for 1948, represents an increase in consumption at the rate of 2,728,000 Mcf. per year. The Commission considers this estimate to be conservative. The Commission finds that the annual increase in consumption in Alberta for the period 1941-1948, was in excess of 2,800,000 Mcf.

(2) The Effect of Prices of Competing Fuels on Consumption of Natural Gas

Coal and gas are competing fuels. Over the past few years the price of gas to users has tended to decline; the price of coal has risen. This favourable price relationship has induced users to substitute gas for coal, and this has contributed to the recent increase in consumption of gas. The future relation between natural gas and coal prices is uncertain. However, it seems reasonable to expect that, if the sale of gas were confined to local markets, the gas resources of the Province would continue to provide a relatively cheap fuel. This incentive to expanding use of gas is therefore likely to continue to be effective.

(3) Increased Industrial Use, as Fuel and Raw Material, to be Expected.

If, along with a favourable price for natural gas, quantities available in the Province remain plentiful and assured, the Commission would expect an increase in the industrial use of gas as a fuel and as a raw material, greater than the increase in the estimates submitted by the Gas Companies. The Commission was impressed by the evidence of J. R. Donald on industrial possibilities based on low-priced natural gas. The establishment of even a few additional large industrial users would increase annual consumption substantially. It would be prudent to take this into account.

(E) Relating Reserves to Anticipated Withdrawals in Alberta

(1) Ratio of Reserves to Withdrawals is approximately 70 to 1

The Commission finds that the ratio of reserves in place to net withdrawals during 1948, was approximately 70 to 1.

This is a high ratio; and the situation might be considered satisfactory even if it were not so high. However, the ratio of reserves to withdrawals, at any time, is less important than its trend.

(2) The Trend of the Ratio is Important

The Commission agrees with the United States Federal Power Commission that the significance of the index represented by the ratio of reserves to production lies particularly in the direction of its trend. "So long as the trend is upward or constant the reserve situation is in a healthy condition . . . . A levelling off of this index or its downward trend would suggest the need for reappraisal of this natural resource, in relation to the consumer requirements to be met, and a closer surveillance of proposed extensions to pipe-line facilities". (Between 1919 and 1946 the index in the United States increased from 20 to 30).

(3) The Ratio Could Increase in the next few Years.

The Commission finds that, although known reserves in Alberta were being depleted for a number of years prior to 1940, since 1940 the ratio of known reserves to withdrawals has been increasing; and the main reasons have been increased exploration, effective conservation measures, and the absence of a market for gas in fields which have been proven.

If it could be assumed that consumption within the Province would increase at a rate of 3,500,000 Mcf. a year, and that consumption would represent 70 percent of withdrawals, annual additions to known reserves of 530,000,000 Mcf. would be sufficient to maintain the ratio of reserves to withdrawals at 70 to 1. In view of current exploratory activity, annual additions might exceed 530,000,000 over the next several years. In that event the ratio of reserves to net production would continue to increase.

(4) An Immediate Increase in Consumption of 22,700,000 Mcf. per Year would Reduce Ratio to 50 to 1.

In view of repeated references to "a period of 50 years", the Commission would point out that the ratio of reserves to production would be reduced to 50 to 1, by an immediate increase in consumption of 22,700,000 Mcf. which amount is 61 percent of present annual consumption.

(5) Additional Reserves Required to Maintain Ratio at 50 to 1 over 50 years

If by an increase in consumption of 22,700,000 Mcf. reserves were now reduced to a ratio of 50 to 1, current consumption being 59,700,000 Mcf. and withdrawals 85,300,000 Mcf. and in succeeding years consumption increased at the rate of 3,500,000 Mcf. per annum, then at the end of 50 years the ratio of reserves to withdrawals would still be 50 to 1, if in the interval new discoveries of gas occurred at the rate of 400,000,000 Mcf. per year.

(6) The Assurance of a Supply of Gas for 50 Years

Maintaining a reserve ratio of 50 to 1 goes much further than "assuring a supply of gas for the next 50 years". In view of the problems of estimating quantities of gas in place and the ultimate recovery of gas, a reserve ratio of 50 to 1 would not assure a supply of gas for 50 years, even if no increase in consumption occurred over the period. Having in mind the further uncertainties of the future with respect to both consumption and discovery of new reserves, the Commission is of the opinion that a supply of gas cannot be guaranteed in any situation for any long period of years, but as long as additions to reserves exceed withdrawals the probability that the supply of gas will last any specific number of years is enhanced.

The following illustrations will serve to indicate the importance of the relation between consumption, withdrawals and additions to reserves **over 50 years:**

(a) If no increase in consumption and withdrawals occurred

Over 50 years, consumption would aggregate 1.86 trillion cubic feet and withdrawals 2.65 trillion cubic feet.[1]

Subject to a reasonable recovery factor, reserves of 4.26 trillion cubic feet would seem to be ample for 50 years without any addition to reserves.[2]

(b) If Alberta consumption increased at the rate of 3,500,000 Mcf. per year

Over 50 years, consumption would aggregate 6.31 trillion cubic feet and withdrawals 9.02 trillion cubic feet.

The new discoveries required to provide for the increase in consumption would have to average approximately 100,000,000 Mcf. per year.

The consumption in the 50th year would be 212,000,000 Mcf.

(c) If an additional 26,000,000 Mcf. were immediately added to Alberta consumption and this part of consumption remained constant

Western Pipe Lines intimated the requirements of its line to Saskatchewan and Manitoba at 26,000,000 Mcf. in the fifth year of operation.

Over 50 years, the added consumption would be 1.3 trillion cubic feet and added withdrawals 1.86 trillion cubic feet.

The new discoveries required to provide for current Alberta consumption, as under (b) above, plus the 26,000,000 Mcf. annually would have to average approximately 140,000,000 Mcf. per year.

The total consumption in the 50th year would be 238,000,000 Mcf.

(d) If an additional 56,000,000 Mcf. were immediately added to Alberta consumption and this part of consumption remained constant

Northwest Natural Gas Company intimated the requirements of its line to the Northwestern States and Vancouver at 56,000,000 Mcf. in the second year of operation.

Over 50 years, the added consumption would be 2.8 trillion cubic feet and added withdrawals 4 trillion cubic feet.

The new discoveries required to provide for current Alberta consumption, as under (b) above, plus the 56,000,000 Mcf. annually would have to average approximately 183,000,000 Mcf.

The total consumption in the 50th year would be 268,000,000 Mcf.

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(1) It is assumed in all cases that consumption represents 70 percent of withdrawals.

(2) In order to meet consumption in the 50th year it is assumed in all illustrations that the reserves in the final year should be at least equal to the estimated withdrawals in that year divided by the estimated weighted load factor. The weighted load factor in the 50th year is estimated at 50 percent.

(e) If Alberta consumption increased at the rate of 3,500,000 Mcf. per year and an additional 82,000,000 Mcf. were added to consumption and this part of consumption remained constant

The sum of the requirements of Western Pipe Lines and Northwest Natural Gas Company is 82,000,000 Mcf.

Over 50 years, consumption would aggregate 8.56 trillion cubic feet, and withdrawals 12.23 trillion cubic feet.

The new discoveries required to provide for the increasing Alberta consumption plus the 82,000,000 Mcf. annually would have to average 220,000,000 Mcf.

The total consumption in the 50th year would be 294,000,000 Mcf.

(7) Judgment is Unavoidable in Weighing Prospects of Future Utilization against Prospective Discoveries

In appraising the natural gas situation in the Province of Alberta, the prospects of increased utilization must be weighed against prospective discoveries of additional reserves. Neither of these factors is measurable beyond a limited number of years. In dealing with the problem judgment is unavoidable.

(F) Further Inquiries into the situation surrounding the use of Natural Gas in the Province of Alberta, having in mind the best interests of the people of the Province of Alberta.

(1) The Principle of Local Priority in the Matter of Supply

The Commission was impressed with the consistency with which the view was expressed that the requirements of the people of the Province should have prior claim on supplies of natural gas within Alberta.

Witnesses appearing on behalf of the Northwest Natural Gas Company, a United States company seeking approval of export of gas from Alberta, fully supported this principle, as did the representative of Western Pipe Lines, a Canadian company proposing to pipe gas from Alberta to Saskatchewan and Manitoba.

The Commission is fully in accord with the principle of local priority in the matter of supply.

(2) The Principle of Priority to Canadian Users

Representations from within Alberta, submissions from other Provinces and the representative of Western Pipe Lines, all urged that service to Canadian users take priority over export from the country. The representative of the British Columbia Electric Company states that the officials of the Northwest Natural Gas Company have expressed their willingness to offer the Vancouver company any form of assurance of priority the Company might desire. There was therefore considerable measure of unanimity on this point.

From the evidence before it, the Commission understands that, under the Natural Gas Act and orders of the United States Federal Power Commission, the policy of protecting, in the matter of supply, customers already attached to pipe lines and of assuring priority to users within the country, has been followed without deviation in the United States.

Experience in Ontario indicates that the problems arising out of uncertain and irregular supply become more acute and difficult of solution where contracts are entered into between nationals of different countries.

The Commission therefore supports the application of the principle of priority to Canadian users.

(3) The Principle of Protection in the Matter of Price

Representatives of consumer interests within the Province were consistent and emphatic in their representation that the sale of gas outside the Province, if permitted, should not be allowed to disturb the structure of gas prices within the Province; and the gas distributing companies in the Province suggested a differential in price in favour of Alberta users.

The Commission is not convinced that sale of gas outside the Province need cause an increase in the price of gas within the Province but the Commission is not in a position to suggest the means by which Alberta users could be protected in the matter of price. These matters raise questions of law on which the Commission is unable to form or offer any opinions.

(4) Maximum Government Revenue Consistent with Development of Resources.

In addition to priority in the matter of supply and protection in the matter of price, the people of Alberta would desire, as a further prerequisite condition to sale of gas outside the Province, that the Government of the Province derive from the disposal of this resource, maximum revenues consistent with continued and sound development of the fuel resources of the Province.

Natural gas is intimately associated with crude oil and natural gasoline. In large measure available natural gas is a by-product of the search for and development of oil and distillate fields. In so far as the necessary costs of petroleum development may be covered in the returns from the sale of oil—and the marked activity in search of oil would suggest that there is some reasonable prospect of this, it is not necessary to recover costs again out of the sale of gas and the prospect of a substantial return from gas, which has not been a significant factor in the past, is not now necessary to promote the further search for oil.

The Commission has studied the revenues which would be obtained by the pipe-line companies at prices which the companies have indicated they would expect to get in markets outside the Province, and the costs, both of gas and of transportation of gas. If the estimated prices in the ultimate markets can be obtained, the revenues available to the gas-producing and pipe-line companies involved in the specific proposals before the Commission, would make it possible for them to contribute very substantially to government revenues.

(5) The Position of the Province of Alberta Appears Strong.

While the Commission is in no position to decide on matters of law, it would appear to us that by reason of the peculiarly favourable position of the Province in regard to fuel resources, of substantial ownership of mineral rights and of jurisdiction over production, the Province of Alberta is in a strong bargaining position. It is clearly in the interests of the people of the Province to use such bargaining strength as the Government may possess, with, at the same time, concern for the sound development of the natural resources of the Province.

(6) A Proposal for an Integrated System of Pipe Lines in the Province.

The Commission has been especially interested in a plan proposed by the gas distributing companies already operating in the Province, to develop an integrated, or "grid" system of pipe lines within the Province, tying together, for purposes of supply, the gas producing fields of Alberta.

It is clear that the disposal of gas from crude oil and distillate fields is likely to remain a major problem in Alberta for some time. From the point of view of conservation and elimination of waste a grid system would have considerable merit. It would make it possible to ensure priority to the utilization of residue gas; dry gas fields could, if necessary, be held in reserve; and such fields might, if circumstances require, be used as storage reservoirs. In other words, gas required for any market, at any time, could be drawn from a source determined by conservation considerations.

As a greatly increased market for gas would be necessary to justify the construction of lines connecting all major producing fields, the proposal of the Alberta gas companies would only be feasible if movement of gas outside the Province were contemplated. In this situation, the plan would appear to have substantial advantages to users within the Province, to the people of the Province generally, and to the companies who might purchase gas for export. However, the capacity of existing pipe lines is inadequate to carry the quantities involved, and replacement of existing lines or construction of new lines would be necessary.

If "export" of gas were permitted, it might occur under three conditions.

First:—pipe line companies desiring to "export" gas might enter into contracts with owners of gas in the Province, freely, and not necessarily with adequate regard to the overall circumstances within the Province. Northwest Natural Gas Company has entered into contracts with gas-owning companies within the Province.

In the opinion of the Commission this is the least desirable of the three possible arrangements.

Second:—by means of long-term contracts, specific fields might be "dedicated" to particular markets within the Province; and exporters might then enter into agreements for the purchase of gas from other fields. This is the situation today in Medicine Hat-Redcliff; and it was generally agreed before the Commission that nothing should be done to prejudice the position of Medicine Hat-Redcliff consumers and industries who are so greatly dependent on natural gas. In representations by the City of Calgary strong exception was taken to action which some years ago deprived the city of the advantages of a long-term contract for gas from Turner Valley, and concern was expressed over the imminent exhaustion of that source of supply. The Commission was further impressed with the argument that, apart entirely from the possibilities of export, the Viking-Kinsella field should be reserved for Edmonton and other points on the system of Northwestern Utilities.

Third:—by "pooling" the gas reserves of the Province, the conservation advantages referred to above would follow, and exporters would secure their supplies out of the general pool. The regulation of withdrawals from particular fields would require to be subject to the approval of the Natural Gas Conservation Board, or some other public regulatory body. The Commission appreciates that the "grid" system proposal presents difficult problems of allocating withdrawals and revenues among different fields and among the various owners of gas within a particular field. However, there is no reason to believe that these difficulties cannot be satisfactorily solved. The Commission can point to the common purchase arrangements already in effect in Turner Valley, and the limited experiment in unit operation in the Jumping Pound Field.

In the opinion of the Commission this appears to be the most desirable of the three possible arrangements.

(7) The Favourable Position of the Province in Respect to Fuel Resources

In the light of current knowledge, the Province of Alberta is in a peculiarly favoured position in regard to fuel and energy resources. Water power resources within or readily accessible to the Province are capable of substantial further development. The quantity of coal underlying the Province is immense, and greatly exceeds the quantity within the boundaries of any other province in the Dominion. Alberta is the only Province which would appear to be in a position to meet its own petroleum requirements, and to have available substantial quantities for "export"; and is in this position without taking into account any prospective use of the tar sands deposits. No other Province has resources of natural gas remotely approaching those of the Province of Alberta. These are known facts.

Resources do no more than occupy space unless they are put to use to serve human needs. The people of the Province of Alberta must ensure that the resources for which they have responsibility, are wisely used with a proper regard to all the legitimate claims that may be made upon them, the present and the future, and the relations between different resources. Particular consideration must be given to the relation between coal and natural gas.

Coal and natural gas are both exhaustible resources, and may readily be substituted the one for the other. Alberta's coal reserves are so huge that, even with greatly accelerated utilization, their ultimate exhaustion would lie in the remote and wholly insignificant future. The evidence that use of oil on the railroads and natural gas in industry and the homes is likely to cause considerable displacement of coal, is a matter of grave concern.

The Western Canada Bituminous Coal Operators' Association stated, "The natural gas industry has made serious inroads into the coal market in recent years to the extent of displacing more than one million tons of coal per annum and will probably continue to do so at an increasing rate. While this situation affects the coal industry adversely, we have no complaint to make in this regard, since we feel that, in the long run the presence of large quantities of oil and gas within the province cannot help but build up the industrial economy of the province, which in turn will benefit the coal industry by largely eliminating its basic problems—transportation and stable markets. We do, however, view the exportation of gas outside the Province with much apprehension".

It should be pointed out that, in considering the total energy situation, the process of displacement might be reversed. The Commission has before it evidence in respect to the conversion of coal into high heat value gas. While this process is technically possible, it is not yet commercially economical, and the product cannot now be considered competitive with natural gas. Significant progress in improvement of technique is being made. The evidence of technically competent witnesses leads the Commission to the conclusion that, if research into the gasification of coal continues to be prosecuted with vigor, long before Alberta's natural gas resources can be exhausted, a high Btu manufactured gas will be available at reduced cost. This possibility must certainly be taken into account in appraising the relation between Alberta's reserves of energy resources and prospective utilization.

(8) Special Consideration to Rural Needs—Electrification and Propane

The Commission recognizes that, because of the cost of transporting and distributing natural gas, the direct benefits of this natural resource, through the availability of a cheap and convenient fuel, accrue largely to urban users. Indirect benefits are received by the rural population both through the growth of urban consuming centres and through the distribution of provincial revenues.

It has been represented to the Commission that, if additional pipe-lines were constructed it would be possible for rural communities to purchase gas from the lines, for local distribution. The Commission has investigated the cost of tapping a pipe line, of transporting the gas to a small town, and of distributing to some 200 domestic customers. The possibility of locating pipe-lines in a position to serve rural communities should be taken into account. Nevertheless, the costs are extremely high, and it cannot be expected that gas will be taken to many rural centres by this means.

As knowledge of reserves develops, it is entirely probable that local supplies will be found adjacent rural towns. The recent provision of gas service in Athabasca is a case in point; and it seems likely that other towns such as Stettler and Hanna will be assured of an adequate local supply of cheap gas.

The attention of the Commission has also been drawn to the possibility of using local supplies of gas for generating power, and of extending farm service lines from local electrical generating plants. The Commission has not been able to secure information on generating costs in gas turbine plants, and consequently has not had an opportunity to determine the economy of extending rural electrification by this means. We would suggest that the use of gas in connection with farm electrification be made the subject of further study.

The Commission received evidence on the increasing use of propane in rural areas in the United States, and on its farm use in Alberta. At present the quantity of propane available for sale to farm users is limited; and at prevailing prices it is being used largely for cooking and water heating. With limited distribution, costs are high, and distribution costs absorb the large part of the price paid by the farmer. Increased utilization on farms depends on an increase in the quantity available, and on a reduction in price at the farm. Increased production of gas in Alberta will result in increased quantities of propane coming available; and, with the handling of larger quantities, distribution costs may be expected to decline. The Commission is of the opinion that propane can contribute greatly to the amenities of farm life. Consequently we would suggest that special and continuous attention be given to ways and means of extending its use throughout the Province.

(9) Conservation and Elimination of Waste

In the light of the waste of gas which occurred during the flush period of production in Turner Valley, the achievements of the industry and of the Petroleum and Natural Gas Conservation Board, in reducing waste and conserving gas, have been commendable.

The Commission appreciates that, under some circumstances, elimination of flaring of gas can only be accomplished by resort to uneconomical measures; and that, following upon the discovery of an oil field, production experience over a period of time may be necessary to determine the most economical use of the gas.

The Commission has not had the opportunity to give adequate consideration to the intricate problems involved in conservation policy; but it appears to us that, in a period when conditions are such as to justify great activity in the search for oil, it is not impossible that the producers of oil could absorb the costs of conservation of gas, without significantly reducing the rate of development of the oil resources.

It is apparent to the Commission that an expended market for gas would be a factor in reducing waste. However, marketing gas would not, under all circumstances, be the most economical use.

(10) Administration and Research

Over the period of our inquiries, the Commission has become increasingly impressed with the magnitude of the petroleum and natural gas resources of Alberta, and with the importance, to the people of the Province, of the wise administration of these resources. The Commission has been equally impressed with the difficult problems involved, and with the high degree of training, ability, experience and judgment which is necessary at the technical level. With every indication of rapid development, the problems and burdens of administration will increase. It is, therefore, clearly to the advantage of the people of the Province that there should be available to the Government of Alberta technical personnel of the highest competence; and that they should be provided with every opportunity to keep abreast of developments in other oil and gas producing areas. The Government should have available to it at all times, full and up-to-date information, not only on the Alberta situation but also on developments in all other oil and gas producing areas in North America.

Complete and accurate statistical information is essential to the wise administration of the natural gas resources of the Province. The Petroleum and Natural Gas Conservation Board can provide complete and accurate statistical information only if it receives the necessary support by way of additional personnel and adequate finances.

In the opinion of the Commission, the Petroleum and Natural Gas Conservation Board should be in a position to provide, at any time, and should publish annually, data on natural gas reserves, exploration and development activity, and consumption of natural gas in the Province. The work of Hume and Ignatieff has provided a foundation on which future estimates of reserves may be built. The Commission suggests that the Conservation Board should be in a position at any time during the year to give an estimate of natural gas reserves, and that along with its annual summary of production, the Board should publish a statement of the reserve position at the beginning of each calendar year, with a summary of developments leading to additions to known reserves during the preceding year. The Members of the Commission believe that a summary of well-drilling, such as that presented to the Commission by a member of the staff of the Conservation Board, would be of general interest. The Commission has found that there is no public body responsible for compiling information on the consumption of natural gas in Alberta. We would suggest that the Conservation Board be responsible for assembling and publishing annual summaries of natural gas consumption in the Province.

Finally, the Commission is of the opinion that the Province of Alberta can afford to give more attention to research into problems related to the use of energy resources. The Commission realizes that research projects in fuels frequently involve substantial expenditures with results which may be either negative or apparent only over a long period of years; and that, its immense fuel resources notwithstanding, the Province of Alberta may not feel justified in making these large expenditures. Nevertheless, the Province should make its contribution to technological research. The Commission therefore urges on the Government that further consideration be given to research in fuels and petro-chemicals, with the object of expanding technical research in the Province, and of coordinating this with technical research programs in effect elsewhere.

There would appear to be a particular need for inquiries directed toward discovering and developing markets for chemicals produced from Alberta's natural gas.

We have the honour to be, Sir,

Your obedient servants.

R. J. DINNING,
Chairman

ANDREW STEWART,
Commissioner

ROY C. MARLER,
Commissioner

Dated at Edmonton, Alberta,
this 8th day of March, A.D. 1949.

APPENDIX I

RATES CHARGED TO CONSUMERS OF NATURAL GAS IN ALBERTA

MEDICINE HAT

(City of Medicine Hat, Natural Gas Department)

Class "A"

Applicable to: General Heating and Cooking, etc. Domestic, Commercial enterprises and public and private institutions, etc.

Fuel Rate:	First	75 M.C.F. per month	25 cents per M.
	Next	125 M.C.F. per month	20 cents per M.
	Next	100 M.C.F. per month	18 cents per M.
	All over	300 M.C.F. per month	15 cents per M.

Minimum Charge—$1.00 for the first 100 M.C.F., then 50c per 100 M.C.F. based on the maximum monthly volume used in any current annual period.

Minimum Bill—$1.00.

Account—Five per cent discount will be allowed to Class "A" customers who pay their current utility accounts within 20 days from the date of same. No meter rental.

Class "B"

Applicable to: Combined Heating and Industrial Process.

Fuel Rate:	First	100 M.C.F. per month	10 cents per M.
	Next	400 M.C.F. per month	8 cents per M.
	All over	500 M.C.F. per month	7 cents per M.

Minimum Charge: $1.00 per 100 M.C.F. based on the maximum monthly volume used in any current annual period.

Account—Net. No meter rental.

New Customers under Class "A" and Class "B" shall pay a minimum monthly charge based on the maximum monthly demand during the first year and as provided for Classes "A" and "B" during subsequent years.

Class "C"

Applicable to: Large industrial power and process, and wholesale contract customers. Limited to minimum of 6 M.M.C.F. per annum, and 50% use of demand.

Demand Charges—$1.00 per 100 M.C.F. per month based on average monthly volume used in the then expired annual period, from 1st January to 31st December.

— PLUS —

Fuel Rate:	Up to	750 M.C.F.	7.0 cents per M.
	Up to	2000 M.C.F.	6.5 cents per M.
	Up to	5000 M.C.F.	5.0 cents per M.
	Up to	15000 M.C.F.	4.0 cents per M.
	Up to	25000 M.C.F.	3.5 cents per M.
	All over	25000 M.C.F.	2.5 cents per M.

Minimum Charge: The demand charge.

Account: Net. No meter rental.

The following is the interpretation in respect of the qualification of customers under the above tariffs:

(1) **Commercial Enterprise**—shall be taken to mean trade or traffic in articles in exchange for each other, or for money or other value, signifying mutual exchange in buying and selling, etc.

(2) **Industrial Process**—shall be interpreted as appertaining to the production of marketable commodities direct from raw materials, in the process of which heat in the form of fuel is required to produce the finished article.

All accounts or rates to be based on metered consumption. No flat rate connections permitted.

WAINWRIGHT

(Wainwright Natural Gas Company)

Limited Rates: fixed by franchise which applies only in the Town of Wainwright.

Domestic Gas: 30 cents per M.C.F.

Commercial and Industrial Gas: 25 cents per M.C.F.

Commercial and Industrial Consumer means a customer who uses at least 5000 M.C.F. per year for each meter installed.

VERMILION

		Gross	Net
First	30 MCF per month	40 cents	38 cents
Next	15 MCF per month	37.5 cents	35.625 cents
Next	15 MCF per month	35 cents	33.25 cents
Next	90 MCF per month	30 cents	28.5 cents
Next	200 MCF per month	22 cents	20 cents

Net rate is applicable on prompt payment of accounts.

ATHABASCA

First	2 MCF per month	$2.00
Next	30 MCF per month	.48
Next	30 MCF per month	.40
Next	58 MCF per month	.38
Next	80 MCF per month	.33
Next	200 MCF per month	.29

Minimum monthly charge—$2.00. If not paid promptly, increase 3c per MCF. The Company is at liberty to sell at less than the above rates if quantity of consumption, the load factor, and off-peak demand warrant it doing so.

NORTHWESTERN UTILITIES LIMITED

Rates charged by Northwestern Utilities Limited are subject to Order No. 10627 of the Board of Public Utility Commissioners, June 6, 1946, and apply to sales of natural gas in the City of Edmonton and to other customers in the municipalities served (except Vegreville).

General Rate:	First 4 M.C.F. or less per month	$2.00
	Excess consumption	20c per M.C.F.

If accounts are not paid on or before the due date, the charge per M.C.F. (other than the first M.C.F.) shall be increased by 2c per M.C.F.

Commercial and Industrial Rate:

(a) For customers whose annual consumption exceeds 13,500 M.C.F. but does not exceed 34,000 M.C.F.

Fixed Charge: $35.00 per month.

Commodity Charge: 17c per M.C.F.

(b) For customers whose annual consumption exceeds 34,000 M.C.F.

Fixed Charge: $20.00 per month.

Commodity Charge: 14c per M.C.F.

If accounts under (a) are not paid on or before the due date, the charge per M.C.F. shall be increased by 2c per M.C.F.

High Load Factory Rate: Available to consumers on annual contract whose annual consumption of gas is not less than 6,000,000 cu. ft. and whose total consumption during the six meter reading periods ending in May, June, July, August, September and October, is not less than 40% of their total consumption for the year.

Fixed Charge: $20.00 per month plus $1.00 per 1,000 cu. ft. of maximum 12-hr. demand.

Commodity Charge:	First 1,000,000 cu. ft.	$ .14 per M.
	Next 1,000,000 cu. ft.	.12 per M.
	All additional	.10 per M.

Minimum Monthly Charge: Fixed Charge.

The above general rate will make available to Edmonton the lowest general rate in Canada and the United States.

GAS RATES AT SOUTHERN EXTENSION

General Rate:

Availability: Available to all customers.

Rates:	First	4 M.C.F.	$2.50
	All additional	M.C.F.	.35 per M.C.F. per month

Minimum: $2.50 per month.

General Conditions: When accounts are not paid on or before the due date the charges per M.C.F. shall be increased by 3c (Three cents) per M.C.F. and the gross rate so arrived at shall apply.

Commercial and Industrial Rates:

Availability: This schedule is available to all Commercial and Industrial customers.

Net Rates: (a) Customers whose annual consumption is not greater than 1,500 M.C.F. per year

Fixed Charge: Five Dollars ($5.00) per month.
plus

Consumption Charge: Twenty-eight cents (28c) per M.C.F.
(b) Customers whose annual consumption is greater than 1,500 M.C.F. per year.

Fixed Charge: Ten Dollars ($10.00) per month.
plus

Consumption Charge: Twenty-four cents (24c) per M.C.F. per month.

General Conditions:

(1) This schedule is available only on annual contract, which shall continue from year to year thereafter until either party shall give to the other party at least thirty (30) days prior to the expiration of any such year a written notice of desire to terminate same, whereupon at the expiration of such year it shall cease and determine.

2. When accounts are not paid on or before the the due date, the charge per M.C.F. shall be increased by three cents (3c) per M.C.F. and the gross rate so arrived at shall then apply.

3. When a customer has been billed under one sub-section (a or b) of this rate and at the end of the year it is found that he should have been billed under another sub-section, his account shall be adjusted and the necessary refund made by the Company.

High Load Factor Rate:

Availability: To consumers on annual contract whose annual consumption of gas is not less than 6,000,000 cu. ft., and whose total consumption during the six meter reading periods ending in May, June, July, August, September and October, is not less than 40% of their total consumption for the year.

Fixed Charge: $20.00 per month plus
$ 1.00 per 1,000 cu. ft. of maximum 12-hour demand.

Commodity Charge:	First 1,000,000 cu. ft.	$ .18 per M.
	Next 1,000,000 cu. ft.	.15 per M.
	All additional	.12 per M.

Determination of Demand: The maximum 12-hour demand shall be the greatest amount of gas in cubic feet delivered in any 12 consecutive hours during the current billing period or the preceding 11 billing periods as ascertained by the Company. In the case of a new consumer of gas, the said maximum 12-hour demand shall be estimated by the Company. The Company will upon receipt of a written request from a consumer install a recording meter to measure the said maximum 12-hour demand. In such event the maximum 12-hour demand established for the current period or for the previous 11 billing periods whether ascertained by the Company as aforesaid or as measured by the said recording meter shall apply. Provided, however, that the Company may with the consent of the consumer estimate the maximum 12-hour demand taking into consideration such factors as the effect of the consumer's demands for gas upon the Company's peak load or any other relevant factor.

Term of Contract: One Year and thereafter until terminated by thirty days' written notice.

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

Schedule of Gas Rates: Effective in Cities of Calgary and Lethbridge, and Towns of Barnwell, Black Diamond, Burdett, Cayley, Claresholm, Coaldale, Foremost, Granum, High River, Macleod, Nanton, Parkland, Stavely, Okotoks, Taber. (Being whole system except Town of Brooks).

Rate No. 1.—Old General Rate—Minimum Charge $1.00 per month.

	Gross	Disc.	Net
First 150 M.C.F.	.37	4	.33
Next 350 M.C.F.	.34	4	.30
Next 500 M.C.F.	.28	3	.25
Next 1000 M.C.F.	.22	2	.20
Next 3000 M.C.F.	.19	2	.17
Excess M.C.F.	.17	2	.15

Conditions:

1. When accounts are not paid on or before the due date the Gross Rate shall apply.
2. Customers making application for service after December 31st, 1939, or Customers who after that date may be cut off for non-payment or for other violations of the Company's "Rules and Regulations" as approved by the Board of Public Utility Commissioners of Alberta, have the option of rates No. 2, No. 3, No. 4, No. 5 or No. 6 where applicable.

Rate No. 2.—Domestic Combination Rate.

First	4 M.C.F.	$1.50 per month.
All additional	M.C.F.	.25 per M.C.F. per month.

Minimum: $1.50 per month.

Available to: Domestic customerss on Annual Contract who, in addition to other general uses of gas, regularly use and depend for space heating service solely upon a gas-fired central heating plant or other gas-fired space heating equipment and take all such gas service through one meter.

Conditions:

1. When accounts are not paid on or before the due date, the charge per M.C.F. other than the first four M.C.F. shall be increased by four cents (4c) per M.C.F. and the Gross Rate so arrived at shall apply.
2. To Customers who have signed a new "Application", this rate shall be effective for all bills payable on or after the first day of January, 1940.
3. To Customers who signed the new "Application" before March 1st, 1940, the Rate shall, if necessary, be retroactive to the date specified in Paragraph 2 above.
4. Having signed an "Application" for this rate, the Customer may not again transfer to the old General Rate.

Rate No. 3.—Commercial and Industrial Combination Rate.

First	4 M.C.F.	$1.50 per month.
All additional	M.C.F.	.26 per M.C.F. per month.

Minimum: $1.50 per month.

Available on: Annual Contract to Commercial and Industrial Customers using less than 7,016 M.C.F. per year, and who, in addition to other general uses of gas, regularly use and depend for space heating service solely upon a gas-fired central heating plant or other gas-fired space heating equipment and who take all such gas service through one meter.

Conditions:

Paragraphs 1, 2, 3, 4, same as Rate 2.

5. When a Customer has been billed under this rate and at the end of the year it is found that he should have been billed under sub-section "A", "Commercial and Industrial Rates", No. 4, his account shall be adjusted and the necessary refund made by the Company.

Rate No. 4.—Commercial and Industrial Rate.

(A) Customers whose annual consumption is greater than 7,016 M.C.F. per year and less than 10,000 M.C.F. per year.

Fixed Charge: ....Eighteen ($18.00) Dollars per month.
plus
Consumption Charge: ....Twenty-three (23c) Cents per M.C.F. per month.

(B) Customers whose annual consumption is greater than 10,000 M.C.F. per year and less than 24,000 M.C.F. per year.

Fixed Charge: ....Sixty ($60.00) Dollars per month.
plus
Consumption Charge: .... Eighteen (18c) Cents per M.C.F. per month.

(C) Customers whose annual consumption is greater than 24,000 M.C.F. per year.

Fixed Charge: ....One Hundred and Twenty ($120.00) Dollars per month.
plus
Consumption Charge: ....Fifteen (15c) Cents per M.C.F. per month.

Conditions:

1. This schedule is available only on annual contract, which shall continue from year to year thereafter until either party shall give the other party at least thirty (30) days prior to

the expiration of any such year, a written notice of desire to terminate same, whereupon at the expiration of such year it shall cease and determine.

2. When accounts are not paid on or before the due date the charge per M.C.F. shall be increased as follows: Rate "A" Four (4) Cents, Rate "B" Three (3) Cents, Rate "C" Two (2) Cents. The gross rate so arrived at shall then apply.
3. When a Customer has been billed under one sub-section (A, B or C) of this Rate and at the end of that year it is found that he should have been billed under another sub-section, his account shall be adjusted and the necessary refund made by the Company.

Rate No. 5.—New General Rate.

Available to: All Customers on Annual Contract.

Fixed Charge: ....One Dollar ($1.00) per month.
plus ....Twenty-six (26c) Cents per M.C.F. per month.

Conditions:

Paragraphs 1, 2, 3, same as Rate No. 2.

4. Having signed an "Application" for this Rate, the Customer may not again transfer to the Old General Rate, but may on Thirty (30) days' notice prior to the expiration of the Annual Contract transfer to any of the other Rates.

Rate No. 6.—High Load Factor Rate.

Availability: To consumers on annual contract whose annual consumption of gas is not less than 24,000 M.C.F. and whose total consumption during the six meter reading periods ending in May, June, July, August, September and October, is not less than 40% of their total consumption for the year.

Fixed Charge: ....$20.00 per month plus
1.00 per month per 1,000 cu. ft. of maximum 12-hour demand.

Commodity Charge:

First	2,000 M.C.F. per month	$ .15 per M.
Next	2,000 M.C.F. per month	.12 per M.
Next	150,000 M.C.F. per month	.10 per M.
All additional per month		.095 per M.

Minimum Monthly Charge: Fixed Charge.

Determination of Demand: The maximum 12-hour demand shall be the greatest amount of gas in cubic feet delivered in any 12 consecutive hours during the current billing period or the preceding 11 billing periods as ascertained by the Company. In the case of a new consumer of gas, the said maximum 12-hour demand shall be estimated by the Company. The Company will upon receipt of a written request from a consumer install a recording meter to measure the said maximum 12-hour demand. In such event the maximum 12-hour demand established for the current period or for the previous 11 billing periods whether ascertained by the Company as aforesaid or as measured by the said recording meter shall apply. Provided, however, that the Company may with the consent of the consumer estimate the maximum 12-hour demand taking into consideration such factors as the effect of the consumer's demands for gas upon the Company's peak load or any other relevant factor.

Term of Contract: One year and thereafter until terminated by thirty days' written notice.

SCHEDULE OF GAS RATES EFFECTIVE IN BROOKS, ALBERTA

Rate "A"—Domestic Combination Rate.

First	4 M.C.F.	$1.50 per month.
All additional	M.C.F.	.27 per M.C.F. per month.

Minimum: $1.50 per month.

Available to: Domestic Customers on Annual Contract who in addition to other general uses of gas regularly use and depend for space heating service solely upon a gas-fired central heating plant or other gas-fired space heating equipment and take all such gas service through one meter.

Rate "B"—Commercial and Industrial Combination Rate.

First	4 M.C.F.	$1.50 per month.
All additional	M.C.F.	.27 per M.C.F. per month.

Available on: Annual Contract to Commercial and Industrial Customers using less than 4,230 M.C.F. per year, and who in addition to other general uses of gas, regularly use and depend for space heating service solely upon a gas-fired central heating plant or other gas-fired space heating equipment and who take all such gas service through one meter.

Rate "C"—New General Rate.

Fixed Charge	$1.00 per month.
plus	.28 per M.C.F. per month.

Available to: All Customers on Annual Contract.

Conditions for Rates "A", "B" and "C" the same as for Rates numbered 2, 3 and 5 respectively for Calgary, Lethbridge and District.

Rate "D"—Commercial and Industrial Rate.

1. Customers whose Annual consumption is greater than 4,230 M.C.F. per year and less than 10,000 M.C.F. per year.
2. Customers whose Annual consumption is greater than 10,000 M.C.F. per year and less than 24,000 M.C.F. per year.
3. Customers whose Annual consumption is greater than 24,000 M.C.F. per year.

Charges for Rate "D" 1, 2 and 3 are the same as charges for Rates numbered 4 A, B and C for Calgary, Lethbridge and District.

Conditions the same as Rate number 4 for Calgary, Lethbridge and District.

Calgary, Alberta,
January 1st, 1948.

APPENDIX II

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	(”)	11	902
	(”)	12	974
	(”)	13	1112
	(”)	21	1995
	John F. Dodge	16	1290
	John D. Dower	7	576
	Kenneth M. Doze	21	1978
	James R. Donald	23	2169
	(recalled)	23	2259
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F.	Henry S. Flock	13	1135
G.	Thomas E. Garside	7	487
	Julian Garrett	12	1050
	(recalled)	13	1068
	(”)	13	1156
	(”)	14	1166
	(”)	19	1586
	D. S. Goodbody	13	1078
	George W. Govier	21	1949
	John Galloway	9	678
			724
H.	Dr. G. S. Hume	2	109
	(recalled)	3	222
	(”)	19	1590
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THE NATURAL GAS COMMISSION
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(Transcript)

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